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**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**North American Electric Reliability )  
Corporation )**

**Docket No. \_\_\_\_\_**

**PETITION OF THE  
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION  
FOR APPROVAL OF REVISIONS TO THE DEFINITION OF “REMEDIAL ACTION  
SCHEME” AND PROPOSED RELIABILITY STANDARDS**

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February 3, 2015

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SCHEME” AND PROPOSED RELIABILITY STANDARDS**

Pursuant to Section 215(d)(1) of the Federal Power Act (“FPA”)<sup>1</sup> and Section 39.5<sup>2</sup> of the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) regulations, the North American Electric Reliability Corporation (“NERC”)<sup>3</sup> hereby submits proposed revisions to the definition of the term “Remedial Action Scheme” (“RAS”) (Exhibit A) in the *NERC Glossary of Terms Used in Reliability Standards* (“NERC Glossary”).<sup>4</sup> NERC is also beginning transition to the use of the term “Remedial Action Scheme” to replace the occurrences of “Special Protection System” (“SPS”) throughout the NERC Reliability Standards. Currently, the terms Special Protection System and Remedial Action Scheme are used interchangeably throughout the NERC Regions and in various Reliability Standards. As a result, NERC also requests Commission approval of the following proposed Reliability Standards (“Proposed Reliability Standards”), which have been modified to incorporate the proposed definition of “Remedial Action Scheme” and eliminate use of the term “Special Protection System”:

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<sup>1</sup> 16 U.S.C. § 824o (2012).

<sup>2</sup> 18 C.F.R. § 39.5 (2014).

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

<sup>4</sup> Unless otherwise designated, all capitalized terms shall have the meaning set forth in the NERC Glossary, available at [http://www.nerc.com/files/Glossary\\_of\\_Terms.pdf](http://www.nerc.com/files/Glossary_of_Terms.pdf).

|                            |                            |                |
|----------------------------|----------------------------|----------------|
| EOP-004-3                  | PRC-005-3(ii) <sup>5</sup> | PRC-023-4      |
| FAC-010-3                  | PRC-012-1 <sup>6</sup>     | TPL-001-0.1(i) |
| FAC-011-3                  | PRC-013-1 <sup>7</sup>     | TPL-002-0(i)b  |
| MOD-030-3                  | PRC-014-1 <sup>8</sup>     | TPL-003-0(i)b  |
| MOD-029-2a                 | PRC-015-1                  | TPL-004-0(i)a  |
| PRC-004-WECC-2             | PRC-016-1                  | PRC-001-1.1(i) |
| PRC-005-2(ii) <sup>9</sup> | PRC-017-1                  |                |

NERC requests that the Commission approve the proposed definition of Remedial Action Scheme and the Proposed Reliability Standards, and find that each is just, reasonable, not unduly discriminatory or preferential, and in the public interest. There are no changes to the Violation Risk Factors or Violation Severity Levels for any of the Proposed Reliability Standards. NERC also requests approval of the associated Implementation Plan (Exhibit C),

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<sup>5</sup> NERC notes that PRC-005-3(i) is proposed in a separate petition for approval of proposed standards developed in Project 2014-01 - Standards Applicability for Dispersed Generation Resources. NERC has included PRC-005-3(ii) for modification in this petition because NERC anticipates Commission action on PRC-005-3(i) on a faster timeline. If the Commission approves the proposed Reliability Standard versions in a different order, NERC will modify numbering accordingly. The changes proposed to the applicability in proposed PRC-005-3(i) are separate and distinct from the changes proposed here to use the single defined term “Remedial Action Scheme” in place of references to “Special Protection System.” NERC also notes that the same change to use the term Remedial Action Scheme is already reflected in the proposed Reliability Standard PRC-005-4 filed in FERC Docket No. RM15-9-000.

<sup>6</sup> The Commission identified PRC-012-0 as a fill-in-the-blank standard in Order No. 693. *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 Fed. Reg. 16416, FERC Stats. & Regs. ¶ 31,242, at P 1517, *order on reh’g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). NERC understands that the Commission will not approve or remand the revised version in this Petition, but the standard has been modified for completeness and so the posted version on NERC’s website reflects the improved definition.

<sup>7</sup> The Commission identified PRC-013-0 as a fill-in-the-blank standard in Order No. 693. *See Order No. 693* at P 1524. NERC understands that the Commission will not approve or remand the revised version in this Petition, but the standard has been modified for completeness and so the posted version on NERC’s website reflects the improved definition.

<sup>8</sup> The Commission identified PRC-014-0 as a fill-in-the-blank standard in Order No. 693. *See Order No. 693* at P 1528. NERC understands that the Commission will not approve or remand the revised version in this Petition, but the standard has been modified for completeness and so the posted version on NERC’s website reflects the improved definition.

<sup>9</sup> NERC notes that PRC-005-2(i) is proposed in a separate petition for approval of proposed standards developed in Project 2014-01 - Standards Applicability for Dispersed Generation Resources. NERC has included PRC-005-2(ii) for modification in this petition because NERC anticipates Commission action on PRC-005-2(i) on a faster timeline. If the Commission approves the proposed Reliability Standard versions in a different order, NERC will modify numbering accordingly. The changes proposed to the applicability in proposed PRC-005-2(i) are separate and distinct from the changes proposed here to use the single defined term “Remedial Action Scheme” in place of references to “Special Protection System.”

noting the explanation below regarding the status of certain of the developed Reliability Standards.

Certain draft Reliability Standards developed by NERC in conjunction with the proposed definition of Remedial Action Scheme have not been submitted in this petition. A complete list of draft Reliability Standards developed in the Project is included in the Implementation Plan. NERC is only requesting approval of the proposed Reliability Standards found in Exhibit B and listed in the petition. The remaining draft Reliability Standards have been marked as “inactive” in accordance with the Implementation Plan language. The Implementation Plan explains that where the standard being modified by the project is replaced by a successor version outside of the project, the proposed Reliability Standard will be marked “inactive” and not become mandatory and enforceable.

As required by Section 39.5(a)<sup>10</sup> of the Commission’s regulations, this petition presents the technical basis and purpose of the proposed definition of Remedial Action Scheme; an explanation of the adjustments made in the proposed Reliability Standards; a summary of the development proceedings (Exhibit H); and a demonstration that the proposed definition and Proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672 (Exhibit D). The NERC Board of Trustees approved the proposed definition of Remedial Action Scheme and the Proposed Reliability Standards on November 13, 2014.

NERC requests that the Commission take final action on this Petition concurrently with NERC’s petition of PRC-010-1. The proposed definitions of UVLS Program and Remedial Action Scheme in each project have been coordinated to cover centrally controlled UVLS as a Remedial Action Scheme. Final action by the Commission is needed contemporaneously on

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<sup>10</sup> 18 C.F.R. § 39.5(a) (2014).

both petitions to facilitate implementation and avoid a gap in coverage of centrally controlled UVLS.

## **I. EXECUTIVE SUMMARY**

A key element for the reliability of the Bulk-Power System is the correct identification and performance of Special Protection Systems and Remedial Action Schemes. NERC is proposing revisions to the existing definition of Remedial Action Scheme and corresponding changes in the Proposed Reliability Standards to use the proposed definition in order to ensure consistent classification of systems that are Remedial Action Schemes and application of Reliability Standards referencing the defined term. The defined terms “Special Protection System” and “Remedial Action Scheme” are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards. NERC will gradually modify all of the NERC Reliability Standards to incorporate the use of only a single term Remedial Action Scheme, starting with revisions to the Proposed Reliability Standards. The proposed revisions to the Remedial Action Scheme definition and Proposed Reliability Standards are not expected to result in changes to the scope of systems covered by the Proposed Reliability Standards and other Reliability Standards that already include the term Remedial Action Scheme. However, in the event there is a change in the status of an entity’s system, the Implementation Plan includes additional time to become compliant.

Although these defined terms share a common definition in the NERC Glossary today, their use and application have been inconsistent as a result of a lack of granularity in the definition and varied regional uses of the terms. The proposed revisions add clarity and granularity that will allow for proper identification of Remedial Action Schemes and a more

consistent application of related Reliability Standards. Use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards. NERC will continue to modify the NERC Reliability Standards until all of them reference only the defined term Remedial Action Scheme. At that time, the definition of Special Protection System will be retired.

## **II. NOTICES AND COMMUNICATIONS**

Notices and communications with respect to this filing may be addressed to the following:<sup>11</sup>

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## **III. BACKGROUND**

### **A. Regulatory Framework**

By enacting the Energy Policy Act of 2005,<sup>12</sup> Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation’s Bulk-Power

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<sup>11</sup> Persons to be included on the Commission’s service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission’s regulations, 18 C.F.R. § 385.203 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

<sup>12</sup> 16 U.S.C. § 824o (2012).

System and of certifying an Electric Reliability Organization (“ERO”) that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)<sup>13</sup> of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)<sup>14</sup> of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)<sup>15</sup> of the Commission’s regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA<sup>16</sup> and Section 39.5(c)<sup>17</sup> of the Commission’s regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

## **B. NERC Reliability Standards Development Procedure**

The proposed definition of Remedial Action Scheme was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.<sup>18</sup> NERC develops Definition in accordance with Section 300 (Reliability Standards

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<sup>13</sup> *Id.* § 824(b)(1).

<sup>14</sup> *Id.* § 824o(d)(5).

<sup>15</sup> 18 C.F.R. § 39.5(a).

<sup>16</sup> 16 U.S.C. § 824o(d)(2).

<sup>17</sup> 18 C.F.R. § 39.5(c)(1).

<sup>18</sup> *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh’g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) (“Further, in considering



Development) of its Rules of Procedure and the NERC Standard Processes Manual.<sup>19</sup> In its order certifying the ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards<sup>20</sup> and thus satisfies certain of the criteria for approving Reliability Standards.<sup>21</sup> The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a definition before the Reliability Standard is submitted to the Commission for approval. The proposed definition of Remedial Action Scheme was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving definitions. Exhibit G includes a summary of the development history and record of development of for the proposed definition of Remedial Action Scheme and the Proposed Reliability Standards.

### **C. Special Protection System and Remedial Action Scheme Definitions**

In Order No. 693, the Commission approved, among other things, the NERC Glossary, which included NERC's current Special Protection System and Remedial Action Scheme definitions.<sup>22</sup> The NERC Glossary currently defines a Special Protection System as:

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to

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

<sup>19</sup> The NERC *Rules of Procedure* are available at <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>. The NERC *Standard Processes Manual* is available at [http://www.nerc.com/comm/SC/Documents/Appendix\\_3A\\_StandardsProcessesManual.pdf](http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf).

<sup>20</sup> 116 FERC ¶ 61,062 at P 250.

<sup>21</sup> Order No. 672 at PP 268, 270.

<sup>22</sup> Order No. 693 at P 1.

maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

The NERC Glossary definition for “Remedial Action Scheme” is a cross-reference to the definition of Special Protection System and reads: “See ‘Special Protection System.’” The internal cross-references from Remedial Action Scheme to Special Protection System in lieu of a separate definition ensures that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.<sup>23</sup> As of the date of this filing, many existing Reliability Standards contain references to both Special Protection System and Remedial Action Scheme in the applicability sections, requirements, tables, or attachments. A summary of the uses of Special Protection System and Remedial Action Scheme in the existing body of Reliability Standards is included in Exhibit E.<sup>24</sup>

#### **D. SPCS Technical Report**

On January 9, 2011, the NERC Standards Committee proposed a request for research to address the misoperation of Special Protection Systems and Remedial Action Schemes and the resultant negative impacts to the reliability of the Bulk Electric System.<sup>25</sup> In that request, the Standards Committee solicited technical input from the NERC Planning Committee on the kind and scope of development necessary to address the identified issues. On June 8, 2011, the NERC Planning Committee approved a joint effort by the System Analysis and Modeling Subcommittee (“SAMS”) and the System Protection and Control Subcommittee (“SPCS”) to

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<sup>23</sup> Where the definition of Special Protection System is referenced in the petition, it also refers to the existing definition of Remedial Action Scheme.

<sup>24</sup> NERC notes that this list was posted with draft 1 of the proposed definition and is current as of June 2014.

<sup>25</sup> See Ex. G at 43.

consider the issues identified in the request for research. Specifically, the project instructed the SPCS and SAMS to:

- assess the Special Protection System-related Protection and Control (“PRC”) Reliability Standards and the definition of Special Protection System;
- conduct an assessment of existing regional practices; and
- document findings on the Special Protection System definition and related Reliability Standards in a report to the Planning Committee.

On March 5, 2013, the SPCS and SAMS issued its report, *Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards* (“SPCS/SAMS Report” or “Report”).<sup>26</sup> A brief summary of the conclusions and recommendations from the Report is provided below.

Following a thorough review, the SPCS/SAMS Report concluded that the existing NERC Glossary definition for Special Protection System is not clear and lacks the specificity to provide for consistent identification and classification of Special Protection Systems or Remedial Action Schemes across the eight NERC Regions. The Report suggested that the lack of clarity and specificity in the definition coupled with varied regional practices employed in the Special Protection System/Remedial Action Scheme-related Reliability Standards, may lead to inconsistent application of these Reliability Standards. To correct the recognized shortcomings of the existing definition of Special Protection System, the SPCS/SAMS Report introduced a strawman definition of “Special Protection System” to eliminate ambiguity in the existing definition and identify thirteen types of schemes that are not Special Protection Systems, but that have been misidentified or confused as Special Protection Systems in the past. Additionally, the

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<sup>26</sup> See Ex. G. The SPCS/SAMS Report was updated in April of 2013.

Report included recommendations for revisions to six Special Protection System-related PRC Reliability Standards to ensure consistency with the strawman Special Protection System definition. The SPCS/SAMS Report suggested implementation of a risk-based classification for Special Protection System, categorizing schemes according to the type of event to which the Special Protection System responds and the consequence of a misoperation of that Special Protection System.

The SPCS/SAMS Report further recommended that NERC reassign requirements of the three Commission-identified “fill-in-the-blank” standards, including PRC-012-0, PRC-013-0, and PRC-014-0, to specific users, owners, and operators. Finally, the SPCS/SAMS Report made a variety of suggestions for revisions to Special Protection System/Remedial Action Scheme-related Reliability Standards, including a proposal to consolidate the requirements pertaining to review, assessment, and documentation of Special Protection System into one standard and to revise requirements pertaining to analysis and reporting of Special Protection System misoperations in a revision of Reliability Standard PRC-016-0.1.

#### **E. History of Project 2010-05**

Project 2010-05 was formed with the goal of improving the monitoring of Bulk Electric System Protection System events and of identifying and correcting the causes of Misoperations to improve Protection System performance. In early 2011, the work in Project 2010-05 was subdivided into two phases, Project 2010-05.1 and Project 2010-05.2, in order to address the work associated with Misoperations of Protection Systems ahead of the work associated with Special Protection Systems and Remedial Action Schemes.<sup>27</sup> In the first phase of the Project,

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<sup>27</sup> See NERC Standards Committee Meeting Minutes (Jun. 9, 2011), available at [http://www.nerc.com/docs/standards/sc/sc\\_060911m\\_package.pdf](http://www.nerc.com/docs/standards/sc/sc_060911m_package.pdf).

NERC developed proposed Reliability Standard PRC-004-3 and a revised definition of “Misoperation”, which are currently pending before the Commission.<sup>28</sup> The second phase of the Project, part of which is the subject of this Petition, addresses the Special Protection System/Remedial Action Scheme aspects of the SPCS/SAMS Report including revisions to the Special Protection System and Remedial Action Scheme definitions. The SPCS/SAMS Report served as a starting point and formed the basis for the standard drafting team’s development work regarding the proposed definition of Remedial Action Scheme. Revisions to the six Special Protection System-related Reliability Standards will be addressed by future work in Project 2010-05.2 during 2015 and a separate petition will be submitted to the Commission.

#### **IV. JUSTIFICATION FOR APPROVAL**

As discussed in Exhibit D and below, the proposed definition of Remedial Action Scheme and the Proposed Reliability Standards satisfy the Commission’s criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following section separately provides: (i) an explanation of the need to revise the definition of Remedial Action Scheme; (ii) presentation and discussion of the proposed definition and its elements; (iii) a discussion of the changes to the Proposed Reliability Standards; and (iv) a discussion of the enforceability of the Proposed Reliability Standards.

##### **A. Need for a Revised Definition of Remedial Action Scheme**

As noted by the SPCS/SAMS Report and a reference document prepared by the standard drafting team (“Remedial Action Scheme FAQ”),<sup>29</sup> the existing definition of Special Protection System lacks sufficient clarity for consistent identification of what equipment, or schemes

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<sup>28</sup> See FERC Docket RD14-14-000.

<sup>29</sup> See Ex. F, *Remedial Action Scheme Definition Development Background and Frequently Asked Questions* (“RAS FAQ”) at 1.

qualify as a Special Protection System or Remedial Action Scheme across the eight NERC Regions.<sup>30</sup> According to the Report, the deference to regional practices for classifying Special Protection Systems, coupled with this lack of clarity in the definition, preclude consistent application of NERC Reliability Standard requirements pertaining to Special Protection Systems. In addition, NERC identified that improvements in the classification of protective schemes would result in the use of a single term in place of two terms that share a definition. Both terms are used across the NERC Regions in regional Reliability Standards and in classifications of systems. For example, the term “Remedial Action Scheme” is used in regional Reliability Standards and regional classifications of Special Protection Systems in the Western Interconnection, but both “Remedial Action Scheme” and “Special Protection System” are used in continent-wide Reliability Standards and across other Regions. The use of both terms offers an opportunity for improvement through revision of the definition and eventual use of a single term.

An explanation of the issues identified by the SPCS/SAMS Report and the Remedial Action Scheme FAQ that justify revising the definition are explained below along with an explanation of the role of regional practices employed to classify Special Protection Systems and Remedial Action Schemes under the current definition.

1. Confusion of a Special Protection System as a Subset of a “Protection System”

Inclusion of the words “Protection System” in the definition of “Special Protection System” has raised questions whether this is an intentional reference such that Special Protection Systems are a subset of Protection Systems.<sup>31</sup> While *Special* Protection Systems may include the

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<sup>30</sup> See Ex. F at 1 and Ex. G at 6.

<sup>31</sup> See *id.*.

same types of components as Protection Systems, Special Protection Systems are not limited to detecting faults or abnormal conditions and tripping affected equipment. For example, a Special Protection System may effect a change to the operating state of power system elements to preserve system stability or to avoid unacceptable voltages or overloads in response to system events. There are many reasons for implementing a Special Protection System.<sup>32</sup> A Special Protection System can be implemented to ensure compliance with the TPL Reliability Standards, to mitigate temporary operating conditions or abnormal configurations (e.g., during construction or maintenance activities), or in instances where system operators would not be able to respond quickly enough to avoid adverse system conditions.<sup>33</sup> As a result, identifying a Special Protection System as a *subset* of Protection Systems introduces opportunity for misidentification.

## 2. Lack of Clarity in Actions Stipulated as Characteristics of a SPS

The Special Protection System definition also lacks clarity in the actions stipulated as characteristics of a Special Protection System. The actions listed in the Special Protection System definition are broad and the definition may unintentionally include schemes whose purpose is not expressly related to preserving system reliability in response to predetermined system conditions.<sup>34</sup> Inclusion of *any* scheme taking “corrective actions other than isolation of faulted components to maintain system reliability”<sup>35</sup> could be interpreted to include voltage regulators and switching controls for shunt capacitors. NERC notes that these individual devices provide local area monitoring and control functions to maintain the local system at its nominal state; consequently, they are not Remedial Action Schemes. Inclusion as a Remedial Action Scheme would unintentionally make these devices subject to single component failure

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<sup>32</sup> Ex. G at 6.

<sup>33</sup> *Id.*

<sup>34</sup> *Id.* at 7.

<sup>35</sup> *See* definition of Special Protection System.

considerations (sometimes referred to as redundancy considerations), coordination, reporting, and maintenance and testing requirements that may be required in the NERC Reliability Standards.<sup>36</sup>

Additionally, “Protection Systems” include components such as “protective relays which respond to electrical quantities” as the building blocks of a Protection System. While all protective schemes include some combination of the building blocks of a Protection System, many protective schemes do not have all of the building blocks. For example, many protective schemes do not have the “communications systems...” component, which is included in the NERC Glossary definition of Protection System. In other cases, protective schemes like Remedial Action Schemes may have all of the components of a Protection System as well as other pieces of equipment such as programmable logic controllers.

#### **B. Proposed Definition of “Remedial Action Scheme” and Related Changes**

NERC’s proposed definition of “Remedial Action Scheme” includes a higher level of specificity and, as a result, will provide more consistent, proper identification of Remedial Action Schemes across the NERC Regions. The proposed definition of Remedial Action Scheme recasts the existing definition of Special Protection System to:

- more precisely describe the objectives of the schemes;
- more precisely describe exclusions;
- state the relationship between Protection Systems and Remedial Action Schemes; and
- clarify that centrally controlled undervoltage-based load shedding is included in the definition.

NERC proposes the following revised definition of Remedial Action Scheme:

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<sup>36</sup> Ex. G at 7.



A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

The definition consists of a “core” definition, which includes a list of objectives (in bullet points) accomplished by a Remedial Action Scheme. It also includes a separate list of exclusions for certain schemes or systems that are not by themselves classified as a Remedial Action Scheme. For each exclusion, the scheme or system could still classify as a Remedial Action Scheme if employed in a broader scheme that meets the definition of Remedial Action Scheme.

NERC is also proposing to move to the use of a single defined term, Remedial Action Scheme, which will eliminate the use of the two terms, SPS and RAS, both within single standards and throughout the NERC Reliability Standards where the terms are used separately. Changes to the Proposed Reliability Standards in this Petition are described separately in Section IV.B below. Use of the term “Remedial Action Scheme” instead of “Special Protection System” eliminates the opportunity to misinterpret Special Protection Systems as a subset of Protection Systems, as noted above, within the Proposed Reliability Standards. Over time, as the references to Special Protection System are converted, the potential for confusion will be eliminated in the Reliability Standards.

A detailed explanation of the proposed definition and its elements along with a summary of the changes in the Proposed Reliability Standards is included below.

1. Definition of Remedial Action Scheme

a) *“Core” Definition with Objectives*

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The revised definition of Remedial Action Scheme addresses ambiguities within the existing definition and provides clarity to promote consistency in the application of the standards by the responsible entities. The definition is not designed to very narrowly define what is considered a Remedial Action Scheme because there are a multitude of reasons that an entity may design a scheme and a narrow definition cannot adequately define all of the possible scenarios an entity may develop and employ a Remedial Action Scheme. A very specific, narrow definition may unintentionally exclude schemes that should be covered. As a result, the standard drafting team designed the definition to be broad enough to include the variety of system conditions monitored and corrective actions taken by Remedial Action Schemes.

Because of the diversity of Remedial Action Schemes, in both action and objective, the practical approach to the definition is to begin with a wide scope, further define objectives that would serve to focus the scope to the desired schemes, and then list specific exclusions to ultimately arrive at what schemes are properly classified as Remedial Action Schemes. The list of corrective actions in the “core” definition and the objectives are not limited because there may another corrective action or objective a scheme is designed for that would justify its treatment as

a Remedial Action Scheme. The items included by the standard drafting team represent an exhaustive list of the commonly applied corrective actions and objectives that would classify the scheme as a Remedial Action Scheme. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as Remedial Action Schemes.

b) *Exclusions*

The proposed “core” definition is broad enough to include the variety of System conditions monitored and corrective actions taken by Remedial Action Schemes. However, NERC proposes an exclusion list as an addition to the Remedial Action Scheme definition to assure that commonly applied protection and control systems are not unintentionally included as Remedial Action Schemes. Without these exclusions, equipment and schemes that should not be considered a Remedial Action Scheme could be subject to the requirements of the Remedial Action Scheme-related NERC Reliability Standards. Each of the exclusions contains a scenario that does not *individually* constitute a Remedial Action Scheme. The language of each exclusion is provided for ease of reference. The exclusions below should not, taken alone, be considered a Remedial Action Scheme because each is either a protective function (e.g., Exclusions a, b, c, e, m, i, and j), a control function (e.g. Exclusions f, g, h, l, n, and k), a combination of both or used for system reconfiguration (e.g., Exclusions d, i, j, and k). These systems generally protect or control an individual piece of equipment or Element or focus on more local action. Remedial Action Schemes are designed to monitor and respond to the larger overall system. Individually, the focus of a protective function is on the Element that it is designed to protect; whereas, a RAS focuses on mitigating unacceptable impacts on the System resulting from the predetermined conditions for which the Remedial Action Scheme was designed.

- a. *Protection Systems installed for the purpose of detecting faults on BES Elements and isolating the faulted Elements*

The standard drafting team has maintained this exclusion in the proposed definition as it is consistent with industry practice of excluding it from consideration as a Special Protection System or Remedial Action Scheme. The existing definition of SPS/RAS excludes the isolation of faulted components because that is a protective function and focuses on a specific Element. For the remaining Protection Systems installed for the purpose of detecting Faults on non-BES Elements, the standard drafting team explains that these are not Remedial Action Schemes, and are not subject to NERC Reliability Standards.

*b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays*

The standard drafting team also carried forward the exclusion of underfrequency load shedding (“UFLS”) and undervoltage load shedding (“UVLS”) found in the definition of Special Protection System as consistent with industry practice. UFLS and UVLS are excluded because they are protective functions that have unique design and implementation considerations covered by NERC Reliability Standards PRC-006-1 and proposed PRC-010-1. The proposed exclusion language emphasizes “distributed relays” to convey that the exclusion covers “UVLS Programs.” The defined term “UVLS Programs” is proposed for approval in NERC’s petition for approval of proposed Reliability Standard PRC-010-1. The proposed definition of “UVLS Program” is “[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.” By excluding distributed UVLS relays in the definition of Remedial Action Scheme and because the proposed UVLS Program definition specifically excludes centrally controlled undervoltage-based load shedding, these centrally controlled undervoltage-

based load shedding schemes are classified as a Remedial Action Scheme via the “core” definition. A centrally controlled scheme allows for a wide-area view. The characteristics of a centrally controlled system make it susceptible to a single point of failure if not properly designed and maintained. Whereas, the UVLS/UFLS programs by their distributed nature have inherent redundancy. While both RAS and UVLS programs can be designed to target severe events, a Remedial Action Scheme can be more selective in its action. A UVLS program is generally based upon individually acting undervoltage relays that take local action. Design for a Remedial Action Scheme can be extremely complex, have greatly varying inputs, and output can result in actions anywhere on the System to mitigate the adverse conditions.

As a result, centrally controlled undervoltage-based load shedding is classified as a Remedial Action Scheme. Both standard drafting teams for the respective projects developing the proposed definitions of Remedial Action Scheme and UVLS Programs agreed that the design and characteristics of centrally controlled undervoltage-based load shedding are appropriately categorized as Remedial Action Scheme.

*c. Out-of-step tripping and power swing blocking*

The existing definition of SPS/RAS excludes out-of-step relaying because it is a protective function. The standard drafting team maintained the exclusion for the same reasons, but changed the wording from “out-of-step relaying” to “out-of-step tripping and power swing blocking” to reflect current industry terminology. Out-of-step tripping is used for controlled system islanding during severe System disturbances resulting in power swings. It is also used to isolate generators that have lost synchronization with System to prevent significant damage. Out-of-step blocking used to prevent unwanted tripping of phased protection relay Elements during either stable or unstable power system swings.

*d. Automatic reclosing schemes*

Automatic reclosing schemes, whether single-pole or three-pole, are used to minimize both system impacts and restoration efforts by System Operators. Automatic reclosing, in itself, is not a Remedial Action Scheme; however, if integrated into a larger scheme that performs additional corrective actions to accomplish the objective(s) listed in the Remedial Action Scheme definition, then it would fall within the definition of Remedial Action Scheme. For example, a scheme that rejects or runs back generation to avoid instability or thermal overloads in addition to initiating automatic reclosing would constitute a Remedial Action Scheme. The standard drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) automatic reclosing schemes. Automatic reclosing schemes that restore load to an alternate source would typically not be a Remedial Action Scheme; however, system reconfiguration which transfers the load to another source for purposes other than load restoration typically would be a Remedial Action Scheme.

*e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service*

Schemes applied on a single element to protect it from damage from non-Fault conditions perform protective functions and are not Remedial Action Schemes. These schemes are designed to protect a single Element when certain non-Fault conditions are present. Examples of these types of schemes are reverse power, volts/hertz, winding temperature, and loss of cooling.

*f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are*

*located at and monitor quantities solely at the same station as the Element being switched or regulated*

- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device*

Consistent with industry practice, controllers that switch or regulate certain devices do not qualify as a Remedial Action Scheme. These controllers monitor local conditions and take local action. In the case of exclusion (g), the purpose of these controllers is to switch shunt devices to restore an acceptable operating range of a single FACTS device. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations. The standard drafting team included these exclusions consistent with industry practice.

- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched*

Schemes or controllers that assist a System Operator in coordinating the switching of shunt reactors and shunt capacitors that would otherwise be manually switched are not remedial in the sense of being mitigations in response to predetermined System conditions, but are for general application to all System conditions, e.g. optimizing voltage profiles or minimizing losses. The standard drafting team included this exclusion consistent with industry practice.

- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open*

When one end of a line is open, unacceptable voltage levels can occur. Opening the remote terminal(s) to de-energize the transmission line removes this voltage rise. Alternatively, restoration conditions may require energization or synchronizing at a specific terminal. These



schemes have not historically been regarded as Remedial Action Scheme, and the standard drafting team included this exclusion consistent with industry practice.

- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)*

These schemes are designed to protect load in an electrical island that might otherwise operate at an off-nominal frequency or voltage, or facilitate restoration. Actions taken on islanded facilities will not impact the interconnected Bulk Electric System because the facilities are isolated. The standard drafting team included this exclusion consistent with industry practice.

- k. Automatic sequences that proceed when manually initiated solely by a System Operator*

Automated sequences created to simplify the actions of a System Operator are not a Remedial Action Scheme because the decision to activate a specific sequence is left to the System Operator. If the automated sequence fails to execute correctly, the System Operator has the option to manually set those actions in motion. The standard drafting team included this exclusion consistent with industry practice. The arming of a Remedial Action Scheme by a System Operator is not the same as manual initiation of an automatic sequence. Arming enables the scheme, but the Remedial Action Scheme must still detect the critical conditions it was designed to mitigate and then take action.

- l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations*

Modulation of HVdc and FACTS via supplementary controls is occasionally used for damping local or inter-area oscillations. It is similar in function to a Power System Stabilizer, which is a component of excitation controls in a generating unit. Power System Stabilizers are

also not classified as Remedial Action Schemes. The standard drafting team included these HVdc and FACTS exclusions consistent with industry practice.

- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)*

Historically, sub-synchronous resonance (“SSR”) protection schemes that directly detect sub-synchronous quantities and the related mitigation are not Remedial Action Schemes. These schemes are designed to detect and mitigate a local area issue. The standard drafting team maintained this exclusion, consistent with industry practice. However, SSR protection schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as Remedial Action Schemes.

- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation (e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing*

These traditional generator and turbine controls are not Remedial Action Schemes. With the exception of automatic generation control, all of these controls involve local monitoring and local control of a specific generator. Automatic generation control is not used for system preservation, but is used for continuous fine-tuning of frequency and to provide balance for load/generation under normal conditions. The standard drafting team included this exclusion consistent with industry practice.

## 2. Proposed Reliability Standards and Implementation

The standard drafting team evaluated all occurrences of Remedial Action Scheme and Special Protection System as part of its scope of work. Exhibit E includes a summary of the occurrences of “Special Protection System” and “Remedial Action Scheme” in the NERC

Reliability Standards (as of May 16, 2014). This document has been included with the Petition as a tool to assist the Commission in reviewing occurrences of the two defined terms. The standard drafting team modified certain Reliability Standards that are currently subject to enforcement and certain others in implementation, where the modification would not impact other ongoing standard development work. The Proposed Reliability Standards, as noted above, reflect the use of the single term “Remedial Action Scheme” and have been revised to remove any reference to Special Protection System in place of references to Special Protection System. For example, in instances where only the term Special Protection System occurs, NERC proposes striking that reference and replacing it with Remedial Action Scheme. Where both terms, Special Protection System and Remedial Action Scheme, occur, NERC proposes deleting only the reference to Special Protection System. Where only the term Remedial Action Scheme occurs, a change is not necessary to the language of the Reliability Standard.

The standard drafting team thoroughly reviewed each of the Proposed Reliability Standards in light of the proposed definition of Remedial Action Scheme and determined that the changes do not affect the scope, intent, or meaning of those Reliability Standards. However, in the event that entities do have schemes that become newly classified as Remedial Action Schemes under the proposed definition, the Implementation Plan includes additional time (within twenty-four months (24) from the Effective Date of the proposed definition) to become compliant with the Reliability Standards during the transition to the proposed definition.

## **V. CONCLUSION**

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

- the proposed definition for “Remedial Action Scheme” in Exhibit A;
- the Proposed Reliability Standards from Exhibit B requested above for approval; and

- the Implementation Plan in Exhibit C.

Respectfully submitted,

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Date: February 3, 2015

**Exhibit A**

**Proposed Definition of “Remedial Action Scheme”**

## Proposed Definition of “Remedial Action Scheme”

### *Remedial Action Scheme (RAS)*

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Existing Definitions – Glossary of Terms Used in NERC Reliability Standards

### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

### *Remedial Action Scheme*

See “Special Protection System”

**Exhibit B**

**Revised Reliability Standards for the Revised Definition of Remedial Action Scheme**



### A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-3
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider

### 5. Effective Dates:

See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

### 6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### **B. Requirements and Measures**

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2-3 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
  
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-3 Attachment 1 and in accordance with the entity responsible for reporting.
  
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
  
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-3 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium]*  
*[Time Horizon: Operations Planning]*
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

### C. Compliance

#### 1. Compliance Monitoring Process

##### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

##### 1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

##### 1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br><br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |

**EOP-004-3 — Event Reporting**

| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)

**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |



**EOP-004-3 — Event Reporting**

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq$ 100 MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq$ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm$ 10% of nominal voltage sustained for $\geq$ 15 continuous minutes.   |

**EOP-004-3 — Event Reporting**

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |

**EOP-004-3 — Event Reporting**

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| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |

EOP-004 - Attachment 2: Event Reporting Form

| <b>EOP-004 Attachment 2: Event Reporting Form</b>   |  |
|---|--|
| <p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a> , Facsimile 404-446-9770 or voice: 404-446-9780.</p>   |  |
| Task  | Comments   |
| 1.  | Entity filing the report include:<br>Company name:<br>Name of contact person:<br>Email address of contact person:<br>Telephone Number:<br>Submitted by (name): |
| 2.  | Date and Time of recognized event.<br>Date: (mm/dd/yyyy)<br>Time: (hh:mm)<br>Time/Zone:  |
| 3.  | Did the event originate in your system?      Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/>                         |
| 4.  | <b>Event Identification and Description:</b>   |
| (Check applicable box)<br><input type="checkbox"/> Damage or destruction of a Facility<br><input type="checkbox"/> Physical Threat to a Facility<br><input type="checkbox"/> Physical Threat to a control center<br><input type="checkbox"/> BES Emergency:<br><input type="checkbox"/> public appeal for load reduction<br><input type="checkbox"/> system-wide voltage reduction<br><input type="checkbox"/> manual firm load shedding<br><input type="checkbox"/> automatic firm load shedding<br><input type="checkbox"/> Voltage deviation on a Facility<br><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)<br><input type="checkbox"/> Loss of firm load<br><input type="checkbox"/> System separation<br><input type="checkbox"/> Generation loss<br><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)<br><input type="checkbox"/> Transmission loss<br><input type="checkbox"/> unplanned control center evacuation<br><input type="checkbox"/> Complete loss of voice communication capability<br><input type="checkbox"/> Complete loss of monitoring capability | Written description (optional):  |

### Guideline and Technical Basis

#### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

#### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

#### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### **Data Gathering**

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### **Law Enforcement Reporting**

The reliability objective of EOP-004-3 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### **Stakeholders in the Reporting Process**

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

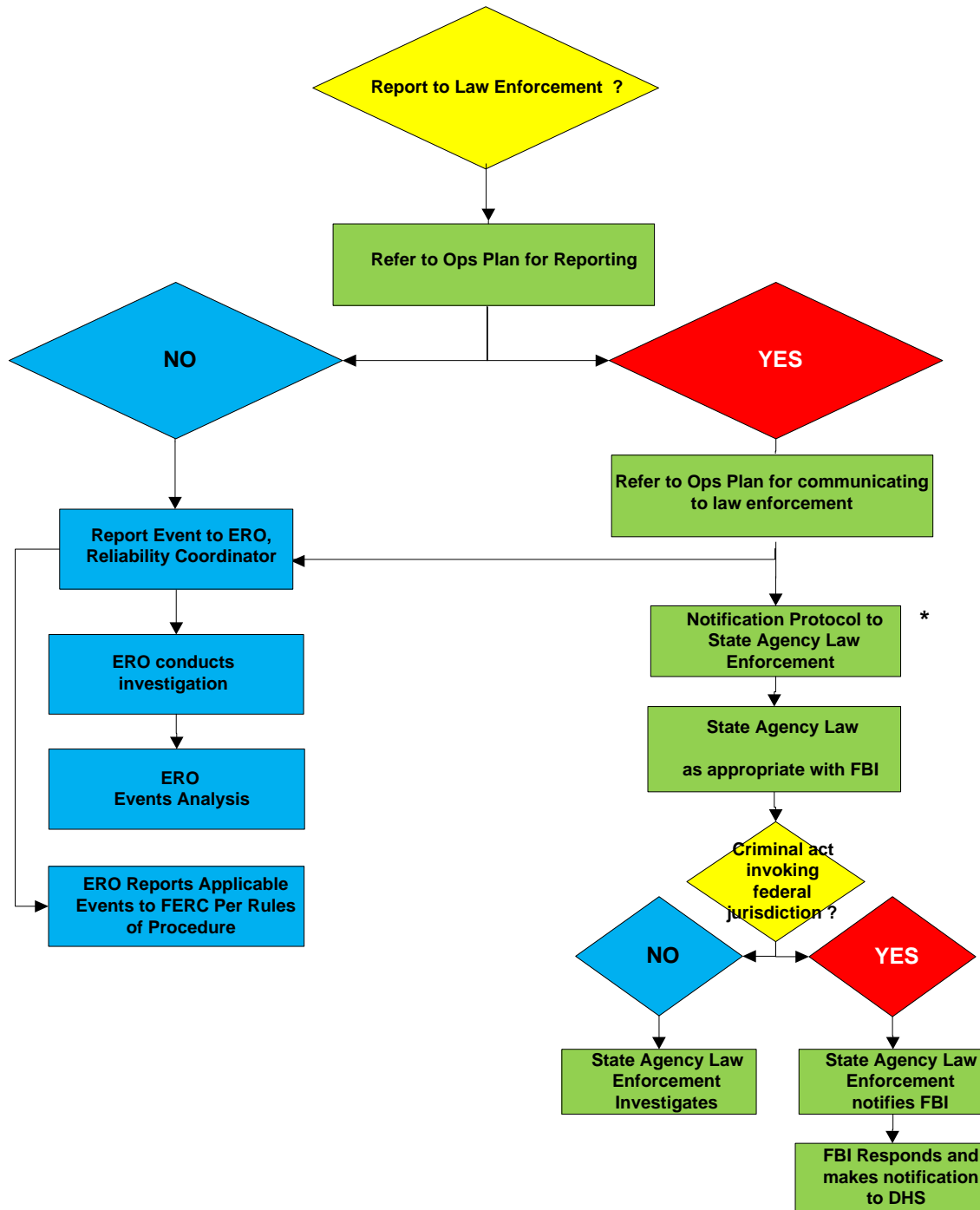
### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.



Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

### **Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts**

#### **Introduction**

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

#### **Summary of Concepts and Assumptions:**

##### ***The Standard:***

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

##### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### **Discussion of Event Reporting**

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### ***What about sabotage?***

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-3 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

## Version History

| Version | Date              | Action   | Change Tracking  |
|---------|-------------------|--|--|
| 2       |                   | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)  |
| 2       | November 7, 2012  | Adopted by the NERC Board of Trustees  |  |
| 2       | June 20, 2013     | FERC approved  |  |
| 3       | November 13, 2014 | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-~~23~~
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider

## 5. Effective Dates:

~~See Implementation Plan for the Revised Definition of “Remedial Action Scheme” The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

## 6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2-3 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-23 Attachment 1 and in accordance with the entity responsible for reporting.
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-23 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the



end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

**1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br><br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |

| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)

**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq$ 100 MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq$ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <del>SPS</del> /RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm$ 10% of nominal voltage sustained for $\geq$ 15 continuous minutes.   |

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |



| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |

EOP-004 - Attachment 2: Event Reporting Form

| <b>EOP-004 Attachment 2: Event Reporting Form</b>   |  |
|---|--|
| <p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a> , Facsimile 404-446-9770 or voice: 404-446-9780.</p>   |  |
| Task  | Comments   |
| 1.  | Entity filing the report include:<br>Company name:<br>Name of contact person:<br>Email address of contact person:<br>Telephone Number:<br>Submitted by (name): |
| 2.  | Date and Time of recognized event.<br>Date: (mm/dd/yyyy)<br>Time: (hh:mm)<br>Time/Zone:  |
| 3.  | Did the event originate in your system?      Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/>                         |
| 4.  | <b>Event Identification and Description:</b>   |
| (Check applicable box)<br><input type="checkbox"/> Damage or destruction of a Facility<br><input type="checkbox"/> Physical Threat to a Facility<br><input type="checkbox"/> Physical Threat to a control center<br><input type="checkbox"/> BES Emergency:<br><input type="checkbox"/> public appeal for load reduction<br><input type="checkbox"/> system-wide voltage reduction<br><input type="checkbox"/> manual firm load shedding<br><input type="checkbox"/> automatic firm load shedding<br><input type="checkbox"/> Voltage deviation on a Facility<br><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)<br><input type="checkbox"/> Loss of firm load<br><input type="checkbox"/> System separation<br><input type="checkbox"/> Generation loss<br><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)<br><input type="checkbox"/> Transmission loss<br><input type="checkbox"/> unplanned control center evacuation<br><input type="checkbox"/> Complete loss of voice communication capability<br><input type="checkbox"/> Complete loss of monitoring capability | Written description (optional):  |

## Guideline and Technical Basis

### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### **Data Gathering**

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-23 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-23 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### **Law Enforcement Reporting**

The reliability objective of EOP-004-23 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### **Stakeholders in the Reporting Process**

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

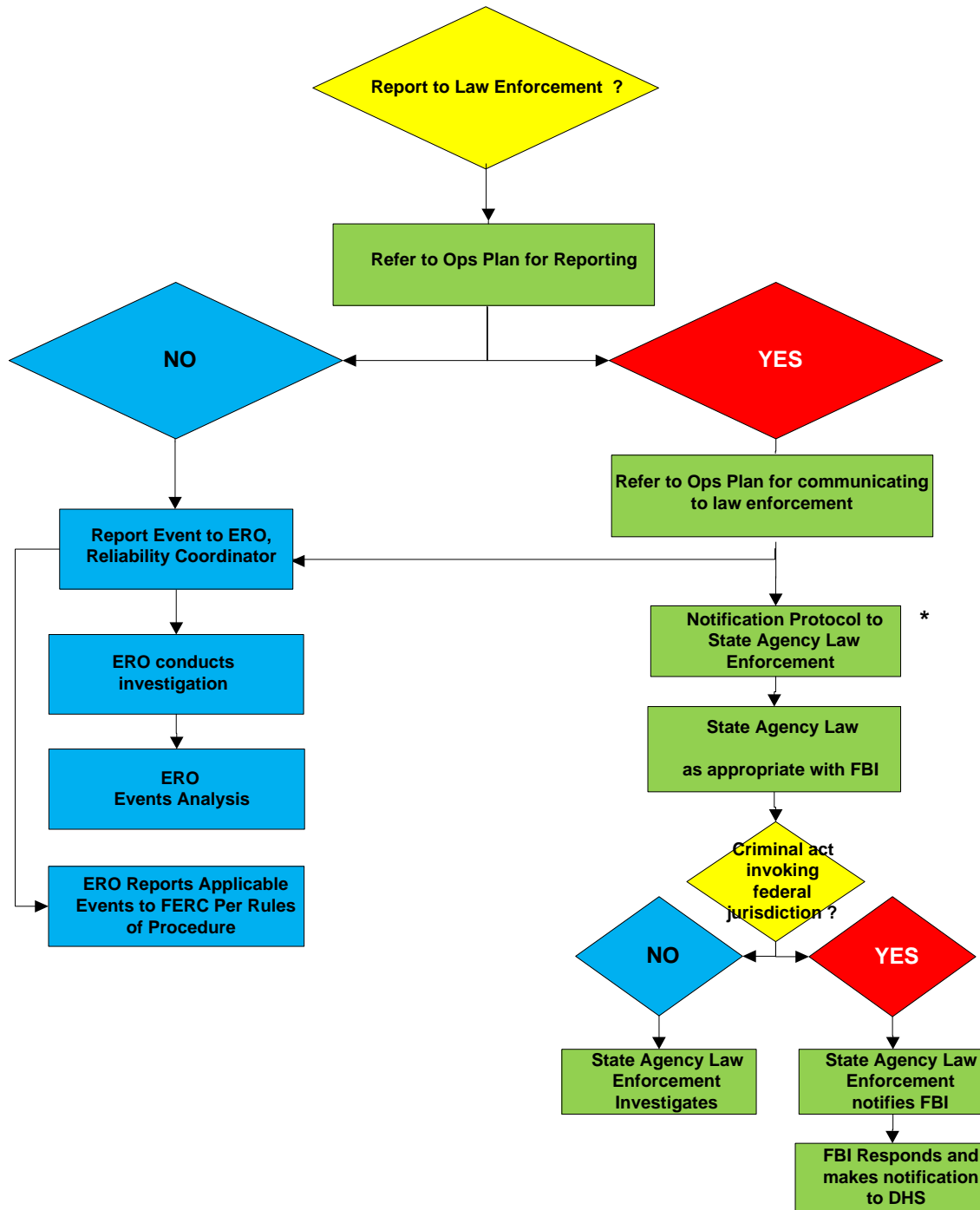
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

## Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

### Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

### Summary of Concepts and Assumptions:

#### *The Standard:*

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

#### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.



3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### **Discussion of Event Reporting**

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### ***What about sabotage?***

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-23 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

### Version History

| Version  | Date                     | Action   | Change Tracking   |
|----------|--------------------------|--|---|
| 2        |                          | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)   |
| 2        | November 7, 2012         | Adopted by the NERC Board of Trustees  |   |
| 2        | June 20, 2013            | FERC approved  |   |
| <u>3</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

- 1. Title:** System Operating Limits Methodology for the Planning Horizon
- 2. Number:** FAC-010-3
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
  - 4.1. Planning Authority**
- 5. Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

**B. Requirements**

- R1.** The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1.** Be applicable for developing SOLs used in the planning horizon.
  - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
  - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Planning Authority’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1.** In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2.** Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1.** Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3.** Starting with all Facilities in service, the system’s response to a single Contingency, may include any of the following:
    - R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

## Standard FAC-010-3 — System Operating Limits Methodology for the Planning Horizon

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- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
- R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
- R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
- R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
- R3.2.** Selection of applicable Contingencies.
- R3.3.** Level of detail of system models used to determine SOLs.
- R3.4.** Allowed uses of Remedial Action Schemes.
- R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
- R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
- R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
- R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
- R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### C. Measures

- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### **1.3. Data Retention**

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### **1.4. Additional Compliance Information**

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

##### **1.4.1** SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

##### **1.4.2** Superseded portions of its SOL Methodology that had been made within the past 12 months.

##### **1.4.3** Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

### **2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**

#### **2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

##### **2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

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- 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology.  
(Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
  - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
  - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
  - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4



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**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6  |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |

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| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |

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| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

**E. Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
- 1.3.1** Cascading does not occur.
- 1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

### Version History

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |

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|-----|-------------------|--|--|
| 2.1 | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |  |
| 2.1 | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.  |  |
| 3   | November 13, 2014 | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** System Operating Limits Methodology for the Planning Horizon
2. **Number:** FAC-010-~~2-13~~
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Planning Authority
5. **Effective Date:** [See Implementation Plan for the Revised Definition of “Remedial Action Scheme” April 19, 2010](#)

## B. Requirements

- R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the planning horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Planning Authority’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3. Starting with all Facilities in service, the system’s response to a single Contingency, may include any of the following:

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
    - R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
  - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
  - R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
  - R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
    - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
  - R3.2.** Selection of applicable Contingencies.
  - R3.3.** Level of detail of system models used to determine SOLs.
  - R3.4.** Allowed uses of ~~Special Protection Systems or~~ Remedial Action ~~Plans~~ Schemes.
  - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
  - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
  - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
  - R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a



change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### **C. Measures**

- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

##### **1.3. Data Retention**

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

##### **1.4. Additional Compliance Information**

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

###### **1.4.1 SOL Methodology.**

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

###### **1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.**

###### **1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.**

- 2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
  - 2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)
  - 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
  - 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
  - 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

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**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6  |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |

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| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |

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| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

## E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a ~~Special Protection~~ System Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |

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|          |                          |  |   |
|----------|--------------------------|--|---|
| 2.1      | November 21, 2013        | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |   |
| 2.1      | February 24, 2014        | Updated VSLs based on June 24, 2013 approval.  |   |
| <u>3</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |



## A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-3
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”.

## B. Requirements

- R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the operations horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Reliability Coordinator’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3. In determining the system’s response to a single Contingency, the following shall be acceptable:

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
    - R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
    - R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
  - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R3.** The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
  - R3.2.** Selection of applicable Contingencies
  - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
    - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
  - R3.4.** Level of detail of system models used to determine SOLs.
  - R3.5.** Allowed uses of Remedial Action Schemes.
  - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
  - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
  - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.
  - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.

**C. Measures**

- M1.** The Reliability Coordinator’s SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### **1.3. Data Retention**

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### **1.4. Additional Compliance Information**

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

**1.4.1** SOL Methodology.

**1.4.2** Superseded portions of its SOL Methodology that had been made within the past 12 months.

**1.4.3** Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

### **2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**

**2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

**2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

**2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

**2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

- 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
- 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
- 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |

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| Requirement | Lower   | Moderate  | High  | Severe   |
|-------------|---|---|---|--|
|             | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p> |

## **Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------------|---|--|
| 1              | November 1, 2006  | Adopted by Board of Trustees  | New  |
| 2              |                   | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised  |
| 2              | June 24, 2008     | Adopted by Board of Trustees: FERC Order 705  | Revised  |
| 2              | January 22, 2010  | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update   |
| 2              | February 7, 2013  | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |  |
| 2              | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |  |
| 2              | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.   |  |
| 3              | November 13, 2014 | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-~~32~~
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”. ~~April 29, 2009~~

## B. Requirements

- R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the operations horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Reliability Coordinator’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3. In determining the system’s response to a single Contingency, the following shall be acceptable:

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.



## C. Measures

- M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- ~~**M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)~~

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### 1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. ~~(Deleted text retired Retirement approved by FERC effective January 21, 2014.)~~

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### 1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

##### 1.4.1 SOL Methodology.

~~1.4.2~~ Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

~~1.4.41.4.2~~ Superseded portions of its SOL Methodology that had been made within the past 12 months.

~~1.4.51.4.3~~ Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

**2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**

**2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

**2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

~~2.2.0~~ No evidence of responses to a recipient's comments on the SOL Methodology (Retirement approved by FERC effective January 21, 2014.)

~~2.3.2.2.~~ **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

~~2.4.2.3.~~ **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

~~2.4.12.3.1~~ The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

~~2.4.22.3.2~~ The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

~~2.4.32.3.3~~ The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

~~2.5.2.4.~~ **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |

| Requirement   | Lower   | Moderate  | High  | Severe   |
|---|---|---|---|--|
|   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>   |
| <p>R5<br/>(Retirement approved by FERC effective January 21, 2014.)</p> | <p><del>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</del></p>   | <p><del>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</del></p>                                     | <p><del>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</del></p> <p>OR</p> <p><del>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</del></p> | <p><del>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</del></p> <p>OR</p> <p><del>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</del></p> |

## Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a ~~Special Protection~~ System Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version       | Date                     | Action  | Change Tracking  |
|---------------|--------------------------|---|--|
| 1             | November 1, 2006         | Adopted by Board of Trustees  | New  |
| 2             |                          | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised  |
| 2             | June 24, 2008            | Adopted by Board of Trustees: FERC Order 705  | Revised  |
| 2             | January 22, 2010         | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update   |
| 2             | February 7, 2013         | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |  |
| 2             | November 21, 2013        | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |  |
| 2             | February 24, 2014        | Updated VSLs based on June 24, 2013 approval.   |  |
| <del>32</del> | <u>November 13, 2014</u> | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



**A. Introduction**

- 1. Title:** Rated System Path Methodology
- 2. Number:** MOD-029-2a
- 3. Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
- 4. Applicability:**
  - 4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
- 5. Proposed Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”.

**B. Requirements**

- R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1.** Includes at least:
      - R1.1.1.1.** The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2.** All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3.** Any other Transmission Operator area linked to the Transmission Operator’s area by joint operating agreement. (Equivalent representation is allowed.)
    - R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.
    - R1.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

- R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).
    - R1.1.5.** Uses Load forecast by Balancing Authority.
    - R1.1.6.** Uses Transmission Facility additions and retirements.
    - R1.1.7.** Uses Generation Facility additions and retirements.
    - R1.1.8.** Uses Remedial Action Scheme (RAS) models where currently existing or projected for implementation within the studied time horizon.
    - R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
    - R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.
  - R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R2.** The Transmission Operator shall use the following process to determine TTC:  
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R2.1.** Except where otherwise specified within MOD-029-2a, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:
    - R2.1.1.** When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
    - R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
    - R2.1.3.** Uncontrolled separation shall not occur.
  - R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Remedial Action Scheme (RAS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a RAS.
  - R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

- R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.
- R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.
- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**NL<sub>F</sub>** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postback_{SF} + counterflow_{SF}$$

**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

**C. Measures**

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.



2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |

**Standard MOD-029-2a — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

**Standard MOD-029-2a — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |

**Version History**

| <b>Version</b> | <b>Date</b>                  | <b>Action</b>                                    | <b>Change Tracking</b>   |
|----------------|------------------------------|--|--|
| 1              | 8/26/2008                    | Adopted by NERC Board of Trustees                |  |
| 1a             | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)  |
| 1a             | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |  |
| 2a             | November 13,<br>2014         | Adopted by the NERC Board of Trustees            | Replaced references to<br>Special Protection<br>System and SPS with<br>Remedial Action Scheme<br>and RAS |

## Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> <li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li> <li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li> <li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li> </ul> <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> <li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li> <li><b>R8.2.</b> Daily values, once per day.</li> <li><b>R8.3.</b> Monthly values, once per week.</li> </ul> |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>   |

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01 Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL<sub>F</sub> is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS<sub>F</sub> is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF<sub>F</sub> is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP<sub>F</sub> is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR<sub>F</sub> is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS<sub>F</sub> is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS<sub>NF</sub> is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF<sub>NF</sub> is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP<sub>NF</sub> is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS<sub>NF</sub> is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could OS<sub>F</sub> in MOD-029-1 Requirement R5 and OS<sub>NF</sub> in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## A. Introduction

1. **Title:** Rated System Path Methodology
2. **Number:** MOD-029-~~21~~a
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”~~Immediately after approval of applicable regulatory authorities.~~

## B. Requirements

- R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1.** Includes at least:
      - R1.1.1.1.** The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2.** All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3.** Any other Transmission Operator area linked to the Transmission Operator’s area by joint operating agreement. (Equivalent representation is allowed.)
    - R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.
    - R1.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.



- R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).
- R1.1.5. Uses Load forecast by Balancing Authority.
- R1.1.6. Uses Transmission Facility additions and retirements.
- R1.1.7. Uses Generation Facility additions and retirements.
- R1.1.8. Uses ~~Special Protection System~~Remedial Action Scheme (SPSRAS) models where currently existing or projected for implementation within the studied time horizon.
- R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
- R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.
- R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R2. The Transmission Operator shall use the following process to determine TTC:  
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
  - R2.1. Except where otherwise specified within MOD-029-21a, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:
    - R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
    - R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
    - R2.1.3. Uncontrolled separation shall not occur.
  - R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a ~~Special Protection System~~Remedial Action Scheme (SPSRAS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a RAS.
  - R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

- R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.
- R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.
- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**NL<sub>F</sub>** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postback_{SF} + counterflow_{SF}$$

**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

### C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a ~~Special Protection System~~Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-~~21~~a and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any

- recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)
- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

#### **1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### **1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |



**Standard MOD-029-21a — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

Standard MOD-029-21a — Rated System Path Methodology

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |

**Version History**

| Version         | Date                         | Action   | Change Tracking  |
|-----------------|------------------------------|--|--|
| 1               | 8/26/2008                    | Adopted by NERC Board of Trustees                |  |
| 1a              | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)  |
| 1a              | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |  |
| <del>21</del> a | <u>November 13,<br/>2014</u> | Adopted by the NERC Board of Trustees            | Replaced references to<br>Special Protection<br>System and SPS with<br>Remedial Action Scheme<br>and RAS |

## Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> <li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li> <li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li> <li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li> </ul> <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> <li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li> <li><b>R8.2.</b> Daily values, once per day.</li> <li><b>R8.3.</b> Monthly values, once per week.</li> </ul> |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>   |

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01 Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL<sub>F</sub> is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS<sub>F</sub> is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF<sub>F</sub> is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP<sub>F</sub> is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR<sub>F</sub> is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS<sub>F</sub> is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS<sub>NF</sub> is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_{NF}$  is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_{NF}$  is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

$OS_{NF}$  is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could  $OS_F$  in MOD-029-1 Requirement R5 and  $OS_{NF}$  in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** **MOD-030-3**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## B. Requirements

- R1.** The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3.** The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4.** If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1.** Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
      - R2.1.1.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the

applicable time periods, including use of Remedial Action Schemes.

**R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

**R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

**R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

**R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area



adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
  - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.
- R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.
- R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ( $ETC_{Fi}$ ) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
  - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC<sub>NFI</sub>) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.
  - R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
  - R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
  - R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.

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<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

**C. Measures**

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

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<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the

value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

#### **1.4. Compliance Monitoring and Enforcement Processes:**



The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |

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| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>   | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>  |

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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>• The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>• The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |

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| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |



**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------------|---|--|
| 2              |                   | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised  |
| 3              | November 13, 2014 | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Flowgate Methodology
2. **Number:** MOD-030-~~023~~
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** ~~-See Implementation Plan for the Revised Definition of “Remedial Action Scheme”~~The date upon which MOD-030-01 is currently scheduled to become effective.

## B. Requirements

- R1.** The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3.** The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4.** If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1.** Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.



- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
  - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
  - If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
  - If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the sink.
  - If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.
  - If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
  - If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R5.1.** Use the models provided by the Transmission Operator.
- R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider’s area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.
- R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.
- R6.** When calculating the impact of ETC for firm commitments (ETC<sub>Fi</sub>) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider’s area, based on:

- R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
  - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.7.** The impact of other firm services determined by the Transmission Service Provider.

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.** When calculating the impact of ETC for non-firm commitments ( $ETC_{NFi}$ ) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.
  - R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.
  - R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider’s area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
  - R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Si}$$

<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**Where:**

**AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NF_i} - CBM_{Si} - TRM_{Ui} + Postbacks_{NF_i} + counterflows$$

**Where:**

**AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

- R10.2.** For daily AFC, once per day.



**R10.3.** For monthly AFC, once per week.

**R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}} \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

## C. Measures

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)

<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)
- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9.

Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>   | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>  |

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>• The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>• The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |



| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |

| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| Version  | Date                     | Action  | Change Tracking   |
|----------|--------------------------|---|---|
| 2        |                          | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised   |
| <u>3</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(i)
3. **Purpose:** To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.
- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

**C. Measures**

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 6 Part 2)

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

**1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will

have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance for Generator Operators:**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

**3. Levels of Non-Compliance for Transmission Operators:**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

**3.3. Level 3:** Not applicable.

**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

**3.4.2** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**4. Levels of Non-Compliance for Balancing Authorities:**

**4.1. Level 1:** Not applicable.

**4.2. Level 2:** Not applicable.

**4.3. Level 3:** Not applicable.

**4.4. Level 4:** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**E. Regional Differences**

None identified.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------------|---|--|
| 0              | April 1, 2005     | Effective Date  | New  |
| 0              | August 8, 2005    | Removed “Proposed” from Effective Date  | Errata   |
| 0              | August 25, 2005   | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata   |
| 1              | November 1, 2006  | Adopted by Board of Trustees  | Revised  |
| 1.1            | April 11, 2012    | Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”) | Errata associated with Project 2007-17   |
| 1.1            | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.  |  |
| 1.1(i)         | November 13, 2014 | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(i)
3. **Purpose:** To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme” January 1, 2007

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.
- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each ~~Special Protection System~~Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

### C. Measures

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the ~~Special Protection Systems~~Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its ~~Special Protection Systems~~Remedial Action Schemes. (Requirement 6 Part 2)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

##### 1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)

- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

## **2. Levels of Non-Compliance for Generator Operators:**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

## **3. Levels of Non-Compliance for Transmission Operators:**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

**3.3. Level 3:** Not applicable.

**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each ~~Special Protection System Remedial Action Scheme~~, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**4. Levels of Non-Compliance for Balancing Authorities:**

4.1. **Level 1:** Not applicable.

4.2. **Level 2:** Not applicable.

4.3. **Level 3:** Not applicable.

4.4. **Level 4:** Did not monitor the status of each ~~Special Protection System Remedial Action Scheme~~, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**E. Regional Differences**

None identified.

**Version History**

| Version       | Date                     | Action  | Change Tracking   |
|---------------|--------------------------|---|---|
| 0             | April 1, 2005            | Effective Date  | New   |
| 0             | August 8, 2005           | Removed “Proposed” from Effective Date  | Errata  |
| 0             | August 25, 2005          | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata  |
| 1             | November 1, 2006         | Adopted by Board of Trustees  | Revised   |
| 1.1           | April 11, 2012           | Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”) | Errata associated with Project 2007-17  |
| 1.1           | September 9, 2013        | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.  |   |
| <u>1.1(i)</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-2
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

**4. Applicability**

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

**B. Requirements**

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection

personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
  - R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
  - R2.3.2.** When FERAS is not available, then
    - 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
    - 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
  - R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or
  - R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
- R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
  - R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

**C. Measures**

**Each measure below applies directly to the requirement by number.**

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
  - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
  - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
  - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
  - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
    - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
  - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
    - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.
  - M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
    - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated

within 20 business days of the misoperation identification.

**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

#### **1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

#### **1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

#### **1.4 Additional Compliance Information**

None.



**2. Violation Severity Levels**

**R1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>  | <b>Severe</b>  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.2.2 and R2.4**

| <b>Lower</b>   | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |

**R3.1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b> |
|----------------|-------------------|---|------------------------|
| 1              | April 16, 2008    | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1            |                        |
| 1              | April 21, 2011    | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |                        |
| 2              | November 13, 2014 | Adopted by the NERC Board of Trustees   |                        |

## A. Introduction

1. **Title:** Protection System and Remedial Action Scheme Misoperation
2. **Number:** PRC-004-WECC-42
3. **Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

### 4. Applicability

- 4.1. Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
  - 4.2. Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
  - 4.3. Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”~~On the first day of the second quarter following applicable regulatory approval.~~

## B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1. System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1. System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2. System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2. Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection

personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
  - R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
  - R2.3.2.** When FERAS is not available, then
    - 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
    - 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
  - R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or
  - R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

**R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

**R3.1.** Identification of a Misoperation of a Protection System and/or RAS,

**R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

### **C. Measures**

**Each measure below applies directly to the requirement by number.**

**M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

**M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.

**M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.

**M2.** Transmission Owners and Generation Owners shall have evidence for the following.

**M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

**M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.

**M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

**M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.

**M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.

**M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.

**M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

**M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.

**M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated

within 20 business days of the misoperation identification.

**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

**R1**

|              |                 |             |               |
|--------------|-----------------|-------------|---------------|
| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|

**WECC Standard PRC-004-WECC-42 — Protection System and Remedial Action Scheme Misoperation**

|   |   |  |  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |
|---|---|--|--|

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |



**R2.2.2 and R2.4**

| <b>Lower</b>   | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |

**R3.1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| <b>Version</b> | <b>Date</b>              | <b>Action</b>   | <b>Change Tracking</b> |
|----------------|--------------------------|---|------------------------|
| 1              | April 16, 2008           | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1            |                        |
| 1              | April 21, 2011           | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |                        |
| <u>2</u>       | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>                                  |                        |

## A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(ii)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:
      - 4.2.6.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above.
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
  - 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

## C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.3. Evidence Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

**1.4. Additional Compliance Information**

None.

### Violation Severity Levels

| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
| R1                 | The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2). | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>   |
| R2                 | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.                       | NA   | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to:</li> </ol> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>  |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |



**Standard PRC-005-2(ii) — Protection System Maintenance**

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| <b>Requirement Number</b> | <b>Lower VSL</b>   | <b>Moderate VSL</b>  | <b>High VSL</b>   | <b>Severe VSL</b>   |
|---------------------------|--|--|---|---|
| R5                        | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

## E. Regional Variances

None

## F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

## Version History

| Version | Date              | Action   | Change Tracking  |
|---------|-------------------|--|--|
| 0       | February 8, 2005  | Adopted by NERC Board of Trustees                              | New  |
| 1       | February 7, 2006  | Adopted by NERC Board of Trustees                              | 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”<br>2. Added “periods” to items where appropriate.<br>Changed “Timeframe” to “Time Frame” in item D, 1.2  |
| 1a      | February 17, 2011 | Adopted by NERC Board of Trustees                              | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17  |
| 1b      | November 5, 2009  | Adopted by NERC Board of Trustees                              | Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10  |
| 1b      | February 3, 2012  | FERC order approving revised definition of “Protection System” | Per footnote 8 of FERC’s order, the definition of “Protection System” supersedes interpretation “b” of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013)<br><i>See N. Amer. Elec. Reliability Corp.</i> , 138 FERC ¶ 61,095 (February 3, 2012) |
| 1.1b    | May 9, 2012       | Adopted by NERC Board of Trustees                              | Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  |

**Standard PRC-005-2(ii) — Protection System Maintenance**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>                        | <b>Change Tracking</b>   |
|----------------|-------------------|--------------------------------------|--|
| 2              | November 7, 2012  | Adopted by NERC Board of Trustees    | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0   |
| 2              | October 17, 2013  | Approved by NERC Standards Committee | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. (no change to standard version number) |
| 2              | March 7, 2014     | Adopted by NERC Board of Trustees    | Modified R1 VSL in response to FERC directive (no change to standard version number)   |
| 2(i)           | November 13, 2014 | Adopted by NERC Board of Trustees    | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources   |
| 2(ii)          | November 13, 2014 | Adopted by NERC Board of Trustees    | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS   |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| <b>Table 1-1</b><br><b>Component Type - Protective Relay</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>   |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 calendar years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

**Table 1-2  
Component Type - Communications Systems  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| <b>Table 1-3</b><br><b>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                   | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified   | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |



Table 1-4(b)

**Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes   | Maximum Maintenance Interval                  | Maintenance Activities  |
|--|---|---|
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|  | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

Table 1-4(c)

**Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <b>Table 1-4(d)</b><br><b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).              |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note:</b> Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted. |                                   |   |
|---|-----------------------------------|---|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).   | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).   | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.  | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.   | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).   | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.   | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 calendar years             | <p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 calendar years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 calendar years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |



| <b>Table 3</b><br><b>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>  |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

**Rationale:**

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

**Rationale for 4.2.5**

In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

**Rationale for 4.2.6:**

Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

## A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(iii)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a ~~Special Protection System (SPS)~~ Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:
      - 4.2.6.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above.
5. **Effective Date:** –See Implementation Plan: for the Revised Definition of “Remedial Action Scheme”

## B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

## C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.3. Evidence Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

**1.4. Additional Compliance Information**

None.

### Violation Severity Levels

| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
| R1                 | The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2). | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>   |
| R2                 | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.                       | NA   | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to:</li> </ol> |



| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>  |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>  | <b>Change Tracking</b>   |
|----------------|-------------------|--|--|
| 0              | February 8, 2005  | Adopted by NERC Board of Trustees                              | New  |
| 1              | February 7, 2006  | Adopted by NERC Board of Trustees                              | 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”<br>2. Added “periods” to items where appropriate.<br>Changed “Timeframe” to “Time Frame” in item D, 1.2  |
| 1a             | February 17, 2011 | Adopted by NERC Board of Trustees                              | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17  |
| 1b             | November 5, 2009  | Adopted by NERC Board of Trustees                              | Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10  |
| 1b             | February 3, 2012  | FERC order approving revised definition of “Protection System” | Per footnote 8 of FERC’s order, the definition of “Protection System” supersedes interpretation “b” of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013)<br><i>See N. Amer. Elec. Reliability Corp.</i> , 138 FERC ¶ 61,095 (February 3, 2012) |
| 1.1b           | May 9, 2012       | Adopted by NERC Board of Trustees                              | Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  |

**Standard PRC-005-2(ii) — Protection System Maintenance**

| <b>Version</b> | <b>Date</b>              | <b>Action</b>                            | <b>Change Tracking</b>   |
|----------------|--------------------------|--|--|
| 2              | November 7, 2012         | Adopted by NERC Board of Trustees        | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0   |
| 2              | October 17, 2013         | Approved by NERC Standards Committee     | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. (no change to standard version number) |
| 2              | March 7, 2014            | Adopted by NERC Board of Trustees        | Modified R1 VSL in response to FERC directive (no change to standard version number)   |
| 2(i)           | November 13, 2014        | Adopted by NERC Board of Trustees        | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources   |
| <u>2(ii)</u>   | <u>November 13, 2014</u> | <u>Adopted by NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>  |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

**Table 1-1  
Component Type - Protective Relay  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes  | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities   |
|---|---|--|
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | <p align="center">12 calendar years</p>   | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p> |

**Table 1-2  
Component Type - Communications Systems  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| <b>Table 1-3<br/>                     Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                   | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified   | None.  |



**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

Table 1-4(b)

**Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes   | Maximum Maintenance Interval                  | Maintenance Activities  |
|--|---|---|
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|  | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

Table 1-4(c)

**Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

**Table 1-4(d)**

**Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for ~~SPSRAS~~, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

**Table 1-4(e)**

**Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for SPSRAS, non-distributed UFLS, and non-distributed UVLS systems**

| Component Attributes  | Maximum Maintenance Interval                       | Maintenance Activities            |
|---|--|-----------------------------------|
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <u>SPSRAS</u> , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <u>SPSRAS</u> except as noted.</b> |                                   |   |
|---|-----------------------------------|---|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).   | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).   | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with <u>SPSRAS</u> .   | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the <u>SPSRAS</u> .  |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.   | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or <u>SPSRAS</u> whose integrity is monitored and alarmed (See Table 2).   | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                   | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.   | No periodic maintenance specified   | None.  |



| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 calendar years             | <p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 calendar years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 calendar years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

**Rationale:**

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

**Rationale for 4.2.5**

In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

**Rationale for 4.2.6:**

Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

## A. Introduction

1. **Title:** **Protection System and Automatic Reclosing Maintenance**
2. **Number:** PRC-005-3(ii)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:
      - 4.2.6.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above.

**4.2.7** Automatic Reclosing<sup>1</sup>, including:

**4.2.7.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

**4.2.7.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.7.3** Automatic Reclosing applied as an integral part of a RAS specified in Section 4.2.4.

**5. Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

**6. Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

## B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

## C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

#### **1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting



Complaint

**1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

**1.4. Additional Compliance Information**

None.

## Violation Severity Levels

| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
| R1                 | The responsible entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | <p>The responsible entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>                        |
| R2                 | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.                       | NA   | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.    |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

## E. Regional Variances

None

## F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

## Version History

| Version | Date              | Action   | Change Tracking   |
|---------|-------------------|--|---|
| 0       | February 8, 2005  | Adopted by NERC Board of Trustees                              | New   |
| 1       | February 7, 2006  | Adopted by NERC Board of Trustees                              | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> </ol> Changed “Timeframe” to “Time Frame” in item D, 1.2                                |
| 1a      | February 17, 2011 | Adopted by NERC Board of Trustees                              | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17   |
| 1b      | November 5, 2009  | Adopted by NERC Board of Trustees                              | Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10   |
| 1b      | February 3, 2012  | FERC order approving revised definition of “Protection System” | Per footnote 8 of FERC’s order, the definition of “Protection System” supersedes interpretation “b” of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013)<br><i>See N. Amer. Elec. Reliability Corp., 138 FERC ¶ 61,095 (February 3, 2012)</i> |
| 1.1b    | May 9, 2012       | Adopted by NERC Board of Trustees                              | Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility   |

**Standard PRC-005-3(ii) — Protection System and Automatic Reclosing Maintenance**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|-------------------|---------------------------------------|--|
| 2              | November 7, 2012  | Adopted by NERC Board of Trustees     | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0   |
| 2              | October 17, 2013  | Approved by NERC Standards Committee  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. (no change to standard version number) |
| 2              | March 7, 2014     | Adopted by NERC Board of Trustees     | Modified R1 VSL in response to FERC directive (no change to standard version number)   |
| 2(i)           | November 13, 2014 | Adopted by NERC Board of Trustees     | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources   |
| 2(ii)          | November 13, 2014 | Adopted by NERC Board of Trustees     | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS   |
| 3              | November 7, 2013  | Adopted by the NERC Board of Trustees | Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs  |

**Standard PRC-005-3(ii) — Protection System and Automatic Reclosing Maintenance**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>                        | <b>Change Tracking</b>   |
|----------------|-------------------|--------------------------------------|--|
| 3              | February 12, 2014 | Approved by NERC Standards Committee | Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of “Unresolved Maintenance Issue” and “Protection System Maintenance Program”. The changes will be reflected in the definitions section of PRC-005-3 for “Unresolved Maintenance Issue” and in the NERC Glossary of Terms for “Protection System Maintenance Program”. (no change to standard version number) |
| 3              | March 7, 2014     | Adopted by NERC Board of Trustees    | Modified R1 VSL in response to FERC directive (no change to standard version number)   |
| 3(i)           | November 13, 2014 | Adopted by NERC Board of Trustees    | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources   |
| 3(ii)          | November 13, 2014 | Adopted by NERC Board of Trustees    | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS   |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.



| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 Calendar Years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| <b>Table 1-2</b><br><b>Component Type - Communications Systems</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 Calendar Months            | Verify that the communications system is functional.   |
|   | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| <b>Table 1-3<br/>                     Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                   | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified   | None.  |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)          |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3) |                              |   |
|--|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |                              |   |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |

| <p align="center"><b>Table 1-4(b)</b><br/> <b>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries</b><br/> <b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b></p> <p align="center">Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p> |   |   |
|---|---|---|
| Component Attributes  | Maximum Maintenance Interval                  | Maintenance Activities  |
|   | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |



| <p style="text-align: center;"><b>Table 1-4(d)</b><br/> <b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br/> <b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b></p> <p style="text-align: center;">Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p> |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|  | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|  | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5<br/>                     Component Type - Control Circuitry Associated With Protective Functions<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                                   |   |
|--|-----------------------------------|---|
| <b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.</b>  |                                   |   |
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 Calendar Years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).              | 6 Calendar Years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.<br>(See Table 4-2(b) for RAS which include Automatic Reclosing.)  | 12 Calendar Years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 Calendar Years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified | None.   |

| <p align="center"><b>Table 2 – Alarming Paths and Monitoring</b></p> <p align="center">In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements</p>   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| <p>Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.</p> <p>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.</p> | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| <p>Alarm Path with monitoring:</p> <p>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.</p>  | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | <p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 Calendar Years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 Calendar Years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing Relay   |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |



| <b>Table 4-2(a)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a RAS</b> |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a RAS.   | 12 Calendar Years                   | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of a RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)                                | No periodic maintenance specified   | None.  |

| <b>Table 4-2(b)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of a RAS</b> |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of a RAS (regardless of any monitoring of the control circuitry).                        | 6 Calendar Years                    | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.                             |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of a RAS.   | 12 Calendar Years                   | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS. |
| Control circuitry associated with Automatic Reclosing that is an integral part of a RAS whose integrity is monitored and alarmed. (See Table 2)  | No periodic maintenance specified   | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

**Rationale:**

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

**Rationale for 4.2.5:**

In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

**Rationale for 4.2.6:**

Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

## A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-3(iii)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a ~~Special Protection System (SPS)~~ Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:
      - 4.2.6.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above.

4.2.7 Automatic Reclosing<sup>1</sup>, including:

4.2.7.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.7.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.7.3 Automatic Reclosing applied as an integral part of ~~an SPS~~ RAS specified in Section 4.2.4.

5. **Effective Date:** See Implementation Plan: for the Revised Definition of “Remedial Action Scheme”

6. **Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

## B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

## C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

#### **1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting



Complaint

### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

### Violation Severity Levels

| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
| R1                 | The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | <p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>                        |
| R2                 | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.                       | NA   | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>                             OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br/>                             OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.  |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

## E. Regional Variances

None

## F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

## Version History

| Version | Date              | Action   | Change Tracking   |
|---------|-------------------|--|---|
| 0       | February 8, 2005  | Adopted by NERC Board of Trustees                              | New   |
| 1       | February 7, 2006  | Adopted by NERC Board of Trustees                              | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> </ol> Changed “Timeframe” to “Time Frame” in item D, 1.2                                |
| 1a      | February 17, 2011 | Adopted by NERC Board of Trustees                              | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17   |
| 1b      | November 5, 2009  | Adopted by NERC Board of Trustees                              | Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10   |
| 1b      | February 3, 2012  | FERC order approving revised definition of “Protection System” | Per footnote 8 of FERC’s order, the definition of “Protection System” supersedes interpretation “b” of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013)<br><i>See N. Amer. Elec. Reliability Corp., 138 FERC ¶ 61,095 (February 3, 2012)</i> |
| 1.1b    | May 9, 2012       | Adopted by NERC Board of Trustees                              | Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility   |

| Version | Date              | Action                                | Change Tracking  |
|---------|-------------------|---------------------------------------|--|
| 2       | November 7, 2012  | Adopted by NERC Board of Trustees     | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0   |
| 2       | October 17, 2013  | Approved by NERC Standards Committee  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. (no change to standard version number) |
| 2       | March 7, 2014     | Adopted by NERC Board of Trustees     | Modified R1 VSL in response to FERC directive (no change to standard version number)   |
| 2(i)    | November 13, 2014 | Adopted by NERC Board of Trustees     | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources   |
| 2(ii)   | November 13, 2014 | Adopted by NERC Board of Trustees     | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS   |
| 3       | November 7, 2013  | Adopted by the NERC Board of Trustees | Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs  |

| Version      | Date                     | Action                                   | Change Tracking  |
|--------------|--------------------------|--|--|
| 3            | February 12, 2014        | Approved by NERC Standards Committee     | Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of “Unresolved Maintenance Issue” and “Protection System Maintenance Program”. The changes will be reflected in the definitions section of PRC-005-3 for “Unresolved Maintenance Issue” and in the NERC Glossary of Terms for “Protection System Maintenance Program”. (no change to standard version number) |
| 3            | March 7, 2014            | Adopted by NERC Board of Trustees        | Modified R1 VSL in response to FERC directive (no change to standard version number)   |
| 3(i)         | November 13, 2014        | Adopted by NERC Board of Trustees        | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources   |
| <u>3(ii)</u> | <u>November 13, 2014</u> | <u>Adopted by NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>  |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.



| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 Calendar Years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 Calendar Months            | Verify that the communications system is functional.   |
|   | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)           |                              |   |
|--|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for <b>SPSRAS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |   |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(b)**  
**Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                  | Maintenance Activities  |
|----------------------|---|---|
|                      | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

Table 1-4(c)  
 Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries  
 Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |



**Table 1-4(d)**  
**Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect: <ul style="list-style-type: none"> <li>Condition of non-battery based dc supply</li> </ul>  |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for <b>SPSRAS</b> , non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|---|--|-----------------------------------|
| Component Attributes  | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <b>SPSRAS</b> , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| Table 1-5<br>Component Type - Control Circuitry Associated With Protective Functions<br>Excluding distributed UFLS and distributed UVLS (see Table 3)                                       |                                   |   |
|---|-----------------------------------|---|
| Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <u>SPSRAS</u> except as noted.  |                                   |   |
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry). | 6 Calendar Years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with <u>SPSRAS</u> .<br>(See Table 4-2(b) for <u>SPSRAS</u> which include Automatic Reclosing.)  | 12 Calendar Years                 | Verify all paths of the control circuits essential for proper operation of the <u>SPSRAS</u> .  |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.   | 12 Calendar Years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or <u>SPSRAS</u> whose integrity is monitored and alarmed (See Table 2).   | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.  | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | <p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 Calendar Years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 Calendar Years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing Relay   |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |



| Table 4-2(a)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of <del>an SPS<sub>a</sub> RAS</del> |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of <del>an SPS<sub>a</sub> RAS</del> .   | 12 Calendar Years                 | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of <del>an SPS<sub>a</sub> RAS</del> and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)           | No periodic maintenance specified | None.  |

**Table 4-2(b)**  
**Maintenance Activities and Intervals for Automatic Reclosing Components**  
**Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of ~~an SPSa~~ RAS**

| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
|--|-----------------------------------|--|
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of <del>an SPSa</del> RAS (regardless of any monitoring of the control circuitry). | 6 Calendar Years                  | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.   |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of <del>an SPSa</del> RAS.  | 12 Calendar Years                 | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the <del>SPSa</del> RAS. |
| Control circuitry associated with Automatic Reclosing that is an integral part of <del>an SPSa</del> RAS whose integrity is monitored and alarmed. (See Table 2)   | No periodic maintenance specified | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

**Rationale:**

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

**Rationale for 4.2.5:**

In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6).- The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. -The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

**Rationale for 4.2.6:**

Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6.- The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

### A. Introduction

1. **Title:** Remedial Action Scheme Review Procedure
2. **Number:** PRC-012-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

### B. Requirements

- R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:
  - R1.1. Description of the process for submitting a proposed RAS for Regional Reliability Organization review.
  - R1.2. Requirements to provide data that describes design, operation, and modeling of a RAS.
  - R1.3. Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4. Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5. Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6. Regional Reliability Organization definition of misoperation.
  - R1.7. Requirements for analysis and documentation of corrective action plans for all RAS misoperations.
  - R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization’s review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9. Determination, as appropriate, of maintenance and testing requirements.
- R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**C. Measures**

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-1\_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-1\_R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-1\_R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-1\_R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-1\_R1.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|-------------------|---------------------------------------|--|
| 0              | April 1, 2005     | Effective Date                        | New  |
| 1              | November 13, 2014 | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

# Standard PRC-012-0—~~Special Protection System~~1 — Remedial Action Scheme Review Procedure

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## A. Introduction

1. **Title:** ~~Special Protection System~~Remedial Action Scheme Review Procedure
2. **Number:** PRC-012-01
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** ~~\_\_\_\_\_~~See Implementation Plan for the Revised Definition of “Remedial Action Scheme” April 1, 2005

## B. Requirements

- R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use ~~an SPS~~a RAS shall have a documented Regional Reliability Organization ~~SPSRAS~~SPSRAS review procedure to ensure that ~~SPSRAS~~SPSRAS comply with Regional criteria and NERC Reliability Standards. The Regional ~~SPSRAS~~SPSRAS review procedure shall include:
  - R1.1. Description of the process for submitting a proposed ~~SPSRAS~~SPSRAS for Regional Reliability Organization review.
  - R1.2. Requirements to provide data that describes design, operation, and modeling of ~~an SPS~~a RAS.
  - R1.3. Requirements to demonstrate that the ~~SPSRAS~~SPSRAS shall be designed so that a single ~~SPSRAS~~SPSRAS component failure, when the ~~SPSRAS~~SPSRAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4. Requirements to demonstrate that the inadvertent operation of ~~an SPS~~a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5. Requirements to demonstrate the proposed ~~SPSRAS~~SPSRAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6. Regional Reliability Organization definition of misoperation.
  - R1.7. Requirements for analysis and documentation of corrective action plans for all ~~SPSRAS~~SPSRAS misoperations.
  - R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization’s review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9. Determination, as appropriate, of maintenance and testing requirements.

~~Adopted by NERC Board of Trustees: February 8, 2005~~

~~Effective Date: April 1, 2005~~

**Standard PRC-012-0 — ~~Special Protection System~~<sup>1</sup> — Remedial Action Scheme Review Procedure**

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- R2.** The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPSRAS review procedure on request (within 30 calendar days).

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**Adopted by NERC Board of Trustees: February 8, 2005**

**2 of 4**

**Effective Date: April 1, 2005**



**C. Measures**

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use ~~an SPS~~a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-~~01~~R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its ~~SPS~~RAS review procedure on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-~~01~~R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-~~01~~R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-~~01~~R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-~~01~~R1.

**E. Regional Differences**

- 1. None identified.

**Version History**

| Version  | Date                     | Action                                       | Change Tracking   |
|----------|--------------------------|--|---|
| 0        | April 1, 2005            | Effective Date                               | New   |
| <u>1</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

~~Adopted by NERC Board of Trustees: February 8, 2005~~



## A. Introduction

1. **Title:** Remedial Action Scheme Database
2. **Number:** PRC-013-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,
  - R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

## C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-1\_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
  - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
  - 1.3. **Data Retention**

None specified.
  - 1.4. **Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-1\_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-1\_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-1\_R1.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|-------------------|---------------------------------------|--|
| 0              | April 1, 2005     | Effective Dave                        | New  |
| 1              | November 13, 2014 | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** ~~Special Protection System~~Remedial Action Scheme Database
2. **Number:** PRC-013-~~01~~
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPSs)~~Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme” — ~~April 1, 2005~~

## B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with ~~an SPS~~a RAS installed shall maintain ~~an SPS~~a RAS database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the ~~SPS~~RAS was designed,
  - R1.2. Operation — The actions taken by the ~~SPS~~RAS in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the ~~SPS~~RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

## C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with ~~an SPS~~a RAS installed, shall have ~~an SPS~~a RAS database as defined in PRC-013-~~01~~\_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
  - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
  - 1.3. **Data Retention**

None specified.
  - 1.4. **Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-~~01~~1\_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-~~91~~1\_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-~~01~~1\_R1.

**E. Regional Differences**

- 1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>              | <b>Action</b>                                | <b>Change Tracking</b>  |
|----------------|--------------------------|--|---|
| 0              | April 1, 2005            | Effective Dave                               | New   |
| <u>1</u>       | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

### A. Introduction

1. **Title:** Remedial Action Scheme Assessment
2. **Number:** PRC-014-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

### B. Requirements

- R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3. The documentation of the Regional Reliability Organization’s RAS assessment shall include the following elements:
  - R3.1. Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3. Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4. Discussion of any coordination problems found between a RAS and other protection and control systems.
  - R3.5. Provide corrective action plans for non-compliant RAS.

### C. Measures

- M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3. The Regional Reliability Organization’s documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-1\_R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-1\_R3.

**2.2. Level 2:** The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-1\_3.

**2.3. Level 3:** The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-1\_R3.

**2.4. Level 4:** The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-1\_R3 or was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date              | Action                                | Change Tracking  |
|---------|-------------------|---------------------------------------|--|
| 0       | April 1, 2005     | Effective Date                        | New  |
| 1       | November 13, 2014 | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## Standard PRC-014-0—~~Special Protection System~~1 — Remedial Action Scheme Assessment

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### A. Introduction

1. **Title:** ~~Special Protection System~~Remedial Action Scheme Assessment
2. **Number:** PRC-014-~~01~~
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** ~~—~~See Implementation Plan for the Revised Definition of “Remedial Action Scheme” April 1, 2005

### B. Requirements

- R1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all ~~SPS~~RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all ~~SPS~~RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3.** The documentation of the Regional Reliability Organization’s ~~SPS~~RAS assessment shall include the following elements:
  - R3.1.** Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3.** Identification of ~~SPS~~RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4.** Discussion of any coordination problems found between a ~~SPS~~RAS and other protection and control systems.
  - R3.5.** Provide corrective action plans for non-compliant ~~SPS~~RAS.

### C. Measures

- M1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all ~~SPS~~RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3.** The Regional Reliability Organization’s documentation of the ~~SPS~~RAS assessment shall include all elements as defined in Reliability Standard PRC-014-~~01~~R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The summary (or detailed) Regional SPSRAS assessment is missing one of the items listed in Reliability Standard PRC-014-~~01~~\_R3.

**2.2. Level 2:** The summary (or detailed) Regional SPSRAS assessment is missing two of the items listed in Reliability Standard PRC-014-~~01~~\_3.

**2.3. Level 3:** The summary (or detailed) Regional SPSRAS assessment is missing three of the items listed in Reliability Standard PRC-014-~~01~~\_R3.

**2.4. Level 4:** The summary (or detailed) Regional SPSRAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-~~01~~\_R3 or was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date                     | Action                                       | Change Tracking   |
|---------|--------------------------|--|---|
| 0       | April 1, 2005            | Effective Date                               | New   |
| 1       | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

### A. Introduction

1. **Title:** Remedial Action Scheme Data and Documentation
2. **Number:** PRC-015-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS
  - 4.2. Generator Owner that owns a RAS
  - 4.3. Distribution Provider that owns a RAS
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-1\_R1 prior to being placed in service.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-1\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-1\_R1 prior to being placed in service.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

**2.2. Level 2:** RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-1\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-1\_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-1\_R1.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 1       | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

# Standard PRC-015-0—~~Special Protection System~~1 — Remedial Action Scheme Data and Documentation

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## A. Introduction

1. **Title:** ~~Special Protection System~~Remedial Action Scheme Data and Documentation
2. **Number:** PRC-015-~~0~~1
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns ~~an SPS~~a RAS
  - 4.2. Generator Owner that owns ~~an SPS~~a RAS
  - 4.3. Distribution Provider that owns ~~an SPS~~a RAS
5. **Effective Date:** ~~—~~See Implementation Plan for the Revised Definition of “Remedial Action Scheme” April 1, 2005

## B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall maintain a list of and provide data for existing and proposed ~~SPS~~RAS as specified in Reliability Standard PRC-013-~~0~~1 R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall have evidence it reviewed new or functionally modified ~~SPS~~RAS in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-~~0~~1 R1 prior to being placed in service.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall provide documentation of ~~SPS~~RAS data and the results of Studies that show compliance of new or functionally modified ~~SPS~~RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

## C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall have evidence it maintains a list of and provides data for existing and proposed ~~SPS~~RAS as defined in Reliability Standard PRC-013-~~0~~1 R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall have evidence it reviewed new or functionally modified ~~SPS~~RAS in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-~~0~~1 R1 prior to being placed in service.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall have evidence it provided documentation of ~~SPS~~RAS data and the results of studies that show compliance of new or functionally modified ~~SPS~~RAS with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**

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Adopted by NERC Board of Trustees: February 8, 2005 November 13, 2014

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** ~~SPSRAS~~ owners provided ~~SPSRAS~~ data, but was incomplete according to the Regional Reliability Organization ~~SPSRAS~~ database requirements.

**2.2. Level 2:** ~~SPSRAS~~ owners provided results of studies that show compliance of new or functionally modified ~~SPSRAS~~ with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-~~01~~\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No ~~SPSRAS~~ data was provided in accordance with Regional Reliability Organization ~~SPSRAS~~ database requirements for Standard PRC-012-~~01~~\_R1, or the results of studies that show compliance of new or functionally modified ~~SPSRAS~~ with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-~~01~~\_R1.

**E. Regional Differences**

1. None identified.

**Version History**

| Version  | Date          | Action                                       | Change Tracking   |
|----------|---------------|--|---|
| 0        | April 1, 2005 | Effective Date                               | New   |
| <u>1</u> | <u>TBD</u>    | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

### A. Introduction

1. **Title: Remedial Action Scheme Misoperations**
2. **Number:** PRC-016-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS.
  - 4.2. Generator Owner that owns a RAS.
  - 4.3. Distribution Provider that owns a RAS.
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1\_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

## Standard PRC-016-1 — Remedial Action Scheme Misoperations

Compliance Monitor: Regional Reliability Organization.

### 1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

**2.2. Level 2:** Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

**2.3. Level 3:** Documentation of RAS misoperations and corrective actions is incomplete.

**2.4. Level 4:** No documentation of RAS misoperations or corrective actions.

## E. Regional Differences

None identified.

## Version History

| Version | Date              | Action   | Change Tracking  |
|---------|-------------------|--|--|
| 0       | April 1, 2005     | Effective Date   | New  |
| 0       | February 8, 2005  | Adopted by NERC Board of Trustees                                    | New  |
| 0       | July 3, 2007      | Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.” | Errata   |
| 0.1     | October 29, 2008  | BOT adopted errata changes; updated version number to “0.1”          | Errata   |
| 0.1     | May 13, 2009      | FERC Approved – Updated Effective Date                               | Revised  |
| 1       | November 13, 2014 | Adopted by the NERC Board of Trustees                                | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



# Standard PRC-016-0.1 — ~~Special Protection System~~ Remedial Action Scheme Misoperations

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## A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Misoperations
2. **Number:** PRC-016-0.1
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns ~~an SPS~~ a RAS.
  - 4.2. Generator Owner that owns ~~an SPS~~ a RAS.
  - 4.3. Distribution Provider that owns ~~an SPS~~ a RAS.
5. **Effective Date:** — See Implementation Plan for the Revised Definition of “Remedial Action Scheme” May 13, 2009

## B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~ a RAS shall analyze its ~~SPS~~ RAS operations and maintain a record of all misoperations in accordance with the Regional ~~SPS~~ RAS review procedure specified in Reliability Standard PRC-012-01\_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~ a RAS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~ a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

## C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~ a RAS shall have evidence it analyzed ~~SPS~~ RAS operations and maintained a record of all misoperations in accordance with the Regional ~~SPS~~ RAS review procedure specified in Reliability Standard PRC-012-01\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~ a RAS shall have evidence it took corrective actions to avoid future misoperations.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~ a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

**Standard PRC-016-0.1 — ~~Special Protection System~~ Remedial Action Scheme Misoperations**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of SPSRAS misoperations is complete but documentation of corrective actions taken for all identified SPSRAS misoperations is incomplete.

**2.2. Level 2:** Documentation of corrective actions taken for SPSRAS misoperations is complete but documentation of SPSRAS misoperations is incomplete.

**2.3. Level 3:** Documentation of SPSRAS misoperations and corrective actions is incomplete.

**2.4. Level 4:** No documentation of SPSRAS misoperations or corrective actions.

**E. Regional Differences**

None identified.

**Version History**

| Version  | Date                     | Action   | Change Tracking   |
|----------|--------------------------|--|---|
| 0        | April 1, 2005            | Effective Date   | New   |
| 0        | February 8, 2005         | Adopted by NERC Board of Trustees                                    | New   |
| 0        | July 3, 2007             | Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.” | Errata  |
| 0.1      | October 29, 2008         | BOT adopted errata changes; updated version number to “0.1”          | Errata  |
| 0.1      | May 13, 2009             | FERC Approved – Updated Effective Date                               | Revised   |
| <u>1</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>                         | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |



### A. Introduction

1. **Title:** Remedial Action Scheme Maintenance and Testing
2. **Number:** PRC-017-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS
  - 4.2. Generator Owner that owns a RAS
  - 4.3. Distribution Provider that owns a RAS
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1. RAS identification shall include but is not limited to:
    - R1.1.1. Relays.
    - R1.1.2. Instrument transformers.
    - R1.1.3. Communications systems, where appropriate.
    - R1.1.4. Batteries.
  - R1.2. Documentation of maintenance and testing intervals and their basis.
  - R1.3. Summary of testing procedure.
  - R1.4. Schedule for system testing.
  - R1.5. Schedule for system maintenance.
  - R1.6. Date last tested/maintained.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-1\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

**1.2. Compliance Monitoring Period and Reset Timeframe**

Compliance Monitor: Regional Reliability Organization.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|-------------------|---------------------------------------|--|
| 0              | April 1, 2005     | Effective Date                        | New  |
| 1              | November 13, 2014 | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard PRC-017-0—~~Special Protection System~~1 — Remedial Action Scheme Maintenance and Testing

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### A. Introduction

1. **Title:** ~~Special Protection System~~Remedial Action Scheme Maintenance and Testing
2. **Number:** PRC-017-~~0~~1
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns ~~an SPS~~a RAS
  - 4.2. Generator Owner that owns ~~an SPS~~a RAS
  - 4.3. Distribution Provider that owns ~~an SPS~~a RAS
5. **Effective Date:** ~~—~~See Implementation Plan for the Revised Definition of “Remedial Action Scheme” April 1, 2005

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1. ~~SPSRAS~~ identification shall include but is not limited to:
    - R1.1.1. Relays.
    - R1.1.2. Instrument transformers.
    - R1.1.3. Communications systems, where appropriate.
    - R1.1.4. Batteries.
  - R1.2. Documentation of maintenance and testing intervals and their basis.
  - R1.3. Summary of testing procedure.
  - R1.4. Schedule for system testing.
  - R1.5. Schedule for system maintenance.
  - R1.6. Date last tested/maintained.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-~~0~~1\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns ~~an SPS~~a RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).



**Standard PRC-017-0—~~Special Protection System~~1 — Remedial Action Scheme  
Maintenance and Testing**

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**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

**1.2. Compliance Monitoring Period and Reset Timeframe**

Compliance Monitor: Regional Reliability Organization.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version  | Date                     | Action                                       | Change Tracking   |
|----------|--------------------------|--|---|
| 0        | April 1, 2005            | Effective Date                               | New   |
| <u>1</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |



### A. Introduction

1. **Title:**           **Transmission Relay Loadability**
2. **Number:**        PRC-023-4
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
  - 4.1. **Functional Entity:**
    - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinator
  - 4.2. **Circuits:**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 **Circuits Subject to Requirement R6:**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”.

### B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

#### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

##### 1.2. Data Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-4 — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
|             |       |  |  | <p>OR</p> <p>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.</p>  |
| <b>R4</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.</p> |
| <b>R5</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.</p>  |
| <b>R6</b>   | N/A   | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more</p> | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24</p> | <p>The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>  |



**Standard PRC-023-4 — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |

**Standard PRC-023-4 — Transmission Relay Loadability**

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| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
|             |       | <p>the list was established or updated. (part 6.2)</p> |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None.

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |

## Standard PRC-023-4 — Transmission Relay Loadability

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| Version | Date              | Action                                | Change Tracking  |
|---------|-------------------|---------------------------------------|--|
| 4       | November 13, 2014 | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023-4 — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

### PRC-023-4 — Attachment B

#### Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

#### Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-4 — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
    - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
    - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
  - e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

## A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-~~43~~
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
  - 4.1. **Functional Entity:**
    - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-~~43~~ - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~43~~ - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-~~43~~ - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinator
  - 4.2. **Circuits:**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 **Circuits Subject to Requirement R6:**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.



4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** [See Implementation Plan for the Revised Definition of “Remedial Action Scheme”](#). ~~See Implementation Plan.~~

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-43, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-43 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-43, Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### **C. Measures**

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-43, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

##### 1.2. Data Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-43 — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High  | Severe   |
|-------------|-------|---|---|--|
|             |       |   |   | OR<br>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.  |

**Standard PRC-023-43 — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |



**Standard PRC-023-43 — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
|             |       | <p>the list was established or updated. (part 6.2)</p> |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None.

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |

**Standard PRC-023-~~43~~ — Transmission Relay Loadability**

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| Version   | Date                     | Action                                | Change Tracking  |
|-----------|--------------------------|---------------------------------------|--|
| <u>43</u> | <u>November 13, 2014</u> | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

PRC-023-43 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for ~~Special Protection Systems~~ Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

PRC-023-43 — Attachment B

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

**A. Introduction**

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(i)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

**B. Requirements**

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
    - R1.3.5. Have all projected firm transfers modeled.

- R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(i)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(i)\_R1 and TPL-001-0.1(i)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(i)\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### **1.2. Compliance Monitoring Period and Reset Time Frame**



Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------------|---|--|
| 0              | April 1, 2005     | Effective Date  | New  |
| 0              | February 8, 2005  | BOT Approval  | Revised  |
| 0              | June 3, 2005      | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata   |
| 0              | July 24, 2007     | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata   |
| 0.1            | October 29, 2008  | BOT adopted errata changes; updated version number to "0.1"       | Errata   |
| 0.1            | May 13, 2009      | FERC Approved – Updated Effective Date                            | Revised  |
| 0.1(i)         | November 13, 2014 | Adopted by the NERC Board of Trustees                             | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-001-0.1(i) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                      |
|--|--|---|--|----------------------|
|  |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers   | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>   | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>   | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |

## Standard TPL-001-0.1(i) — System Performance Under Normal Conditions

|  |   |                |                |                         |                |  |
|--|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|  | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit  | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(i)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** —See Implementation Plan for the Revised Definition of “Remedial Action Scheme” May 13, 2009

## B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
    - R1.3.5. Have all projected firm transfers modeled.

- R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
- R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(i) R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(i) R1 and TPL-001-0.1(i) R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(i) R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version       | Date                     | Action  | Change Tracking   |
|---------------|--------------------------|---|---|
| 0             | April 1, 2005            | Effective Date  | New   |
| 0             | February 8, 2005         | BOT Approval  | Revised   |
| 0             | June 3, 2005             | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata  |
| 0             | July 24, 2007            | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata  |
| 0.1           | October 29, 2008         | BOT adopted errata changes; updated version number to "0.1"       | Errata  |
| 0.1           | May 13, 2009             | FERC Approved – Updated Effective Date                            | Revised   |
| <u>0.1(i)</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>                      | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**Standard TPL-001-0.1(i) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                      |
|--|--|---|--|----------------------|
|  |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers   | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>   | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>   | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |

**Standard TPL-001-0.1(i) — System Performance Under Normal Conditions**

|  |   |  |
|--|---|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol>  | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|  | <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant <del>Special Protection System (or remedial action scheme)</del> Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.



**A. Introduction**

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0(i)b
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.

## **Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

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- R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.
- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0(i)b\_R1 and TPL-002-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0(i)b\_R3.

### **D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

## Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element

**Compliance Monitor:** Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

1. None identified.

## Version History

| Version | Date               | Action   | Change Tracking   |
|---------|--------------------|--|---|
| 0       | February 8, 2005   | Adopted by NERC Board of Trustees  | New   |
| 0       | April 1, 2005      | Effective Date   | New   |
| 0a      | July 30, 2008      | Adopted by NERC Board of Trustees  | New   |
| 0a      | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised   |
| 0b      | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation  |
| 0b      | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation  |
| 0(i)b   | TBD                | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with |

**Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

|  |  |  |                                |
|--|--|--|--------------------------------|
|  |  |  | Remedial Action Scheme and RAS |
|--|--|--|--------------------------------|

**Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

**Table I. Transmission System Standards — Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

## Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element

|   |   |                |                |                         |                |  |
|---|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <p>5. Breaker (failure or internal Fault)</p> <hr style="border-top: 1px dashed black;"/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**Appendix 1**

**Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

**TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**Requirement R1.3.2**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2  
Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.



**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Appendix 2**

| <b>Requirement Number and Text of Requirement</b>  |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| <b>Background Information for Interpretation</b>   |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> <li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li> <li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li> <li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li> </ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> </ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>4. Single Pole (dc) Line</li> </ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| <b>Conclusion</b>  |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

## **Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

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More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

**A. Introduction**

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0(i)b
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”~~Immediately after approval of applicable regulatory authorities.~~

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
- R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.

## **Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

- R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.
- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0(i)b\_R1 and TPL-002-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0(i)b\_R3.

### **D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

## Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element

**Compliance Monitor:** Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

1. None identified.

## Version History

| Version      | Date               | Action   | Change Tracking  |
|--------------|--------------------|--|--|
| 0            | February 8, 2005   | Adopted by NERC Board of Trustees  | New  |
| 0            | April 1, 2005      | Effective Date   | New  |
| 0a           | July 30, 2008      | Adopted by NERC Board of Trustees  | New  |
| 0a           | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0b           | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation   |
| 0b           | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation   |
| <u>0(i)b</u> | <u>TBD</u>         | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with</u> |

**Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

|  |  |  |   |
|--|--|--|---|
|  |  |  | <u>Remedial Action Scheme<br/>and RAS</u> |
|--|--|--|---|

Table I. Transmission System Standards — Normal and Emergency Conditions

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |



## Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element

|   |   |   |
|---|---|---|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol>  | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant <del>Special Protection System (or remedial action scheme)</del> Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Appendix 1

### Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### Requirement R1.3.2

#### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2  
Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

## Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p style="padding-left: 40px;"><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| Background Information for Interpretation  |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> <li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li> <li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li> <li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li> </ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> </ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>4. Single Pole (dc) Line</li> </ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| Conclusion   |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

**A. Introduction**

1. **Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. **Number:** TPL-003-0(i)b
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
- R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

## **Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

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- R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
  - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
  - R1.3.11.** Include the effects of existing and planned control devices.
  - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0(i)b\_R1 and TPL-003-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0(i)b\_R3.

### **D. Compliance**

- 1. Compliance Monitoring Process**



## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

### 1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

1. None identified.

## Version History

| Version | Date              | Action   | Change Tracking  |
|---------|-------------------|--|--|
| 0       | February 8, 2005  | Adopted by NERC Board of Trustees  | New  |
| 0       | April 1, 2005     | Effective Date   | New  |
| 0       | April 1, 2005     | Add parenthesis to item “e” on page 8.   | Errata   |
| 0a      | July 30, 2008     | Adopted by NERC Board of Trustees  |  |
| 0a      | October 23, 2008  | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0a      | April 23, 2010    | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation   |
| 0b      | February 7, 2013  | Interpretation adopted by NERC Board of Trustees   |  |
| 0b      | June 20, 2013     | FERC order issued approving Interpretation   |  |
| 0(i)b   | November 13, 2014 | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                                |
|---|--|---|--|--------------------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No           |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

|   |   |              |                |                         |                |  |
|---|---|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <hr/> <p>5. Breaker (failure or internal Fault)</p> <hr/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer  |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## **Appendix 1**

### **Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### **Requirement R1.3.2**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."



## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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### Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

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<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

**A. Introduction**

- 1. Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- 2. Number:** TPL-003-0(i)b
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** ~~\_\_\_\_\_~~ See Implementation Plan for the Revised Definition of “Remedial Action Scheme” April 23, 2010

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
- R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

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- R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
  - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
  - R1.3.11.** Include the effects of existing and planned control devices.
  - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0(i)b\_R1 and TPL-003-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0(i)b\_R3.

### **D. Compliance**

- 1. Compliance Monitoring Process**

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version      | Date                     | Action   | Change Tracking   |
|--------------|--------------------------|--|---|
| 0            | February 8, 2005         | Adopted by NERC Board of Trustees  | New   |
| 0            | April 1, 2005            | Effective Date   | New   |
| 0            | April 1, 2005            | Add parenthesis to item “e” on page 8.   | Errata  |
| 0a           | July 30, 2008            | Adopted by NERC Board of Trustees  |   |
| 0a           | October 23, 2008         | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised   |
| 0a           | April 23, 2010           | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation  |
| 0b           | February 7, 2013         | Interpretation adopted by NERC Board of Trustees   |   |
| 0b           | June 20, 2013            | FERC order issued approving Interpretation   |   |
| <u>0(i)b</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Table I. Transmission System Standards – Normal and Emergency Conditions

| Category  | Contingencies  | System Limits or Impacts  |  |                                |
|---|--|---|--|--------------------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No           |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

|   |  |              |                |                         |                |  |
|---|--|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <hr/> <p>5. Breaker (failure or internal Fault)</p> <hr/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant <del>Special Protection System (or remedial action scheme)</del> Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer   |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section   |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.



## Appendix 1

### Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### Requirement R1.3.2

#### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

### Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.



### A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0(i)a
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** See Implementation Plan for the Revised Definition of “Remedial Action Scheme”

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.
    - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
    - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

**R1.3.8.** Include the effects of existing and planned control devices.

**R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

**R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

**C. Measures**

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0(i)a\_R1.

**M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0(i)a\_R1.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Not applicable.

**E. Regional Differences**

**1.** None identified.

**Version History**

| Version | Date          | Action         | Change Tracking |
|---------|---------------|----------------|-----------------|
| 0       | April 1, 2005 | Effective Date | New             |

## Standard TPL-004-0(i)a — System Performance Following Extreme BES Events

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|       |                   |  |  |
|-------|-------------------|--|--|
| 0a    | February 7, 2013  | Interpretation adopted by NERC Board of Trustees |  |
| 0a    | June 20, 2013     | Interpretation approved in FERC order            |  |
| 0(i)a | November 13, 2014 | Adopted by the NERC Board of Trustees            | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-004-0(i)a — System Performance Following Extreme BES Events**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

## Standard TPL-004-0(i)a — System Performance Following Extreme BES Events

|   |   |  |
|---|---|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|---|---|--|

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**Appendix 1**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.



The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## **Standard TPL-004-0(i)a — System Performance Following Extreme BES Events**

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

## A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0(i)a
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** ~~\_\_\_\_\_~~ See Implementation Plan for the Revised Definition of “Remedial Action Scheme” April 1, 2005

## B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.
    - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
    - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

**R1.3.8.** Include the effects of existing and planned control devices.

**R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

**R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

**C. Measures**

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0(i)a\_R1.

**M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0(i)a\_R1.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Not applicable.

**E. Regional Differences**

**1.** None identified.

**Version History**

| Version | Date          | Action         | Change Tracking |
|---------|---------------|----------------|-----------------|
| 0       | April 1, 2005 | Effective Date | New             |

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|              |                          |  |   |
|--------------|--------------------------|--|---|
| 0a           | February 7, 2013         | Interpretation adopted by NERC Board of Trustees |   |
| 0a           | June 20, 2013            | Interpretation approved in FERC order            |   |
| <u>0(i)a</u> | <u>November 13, 2014</u> | <u>Adopted by the NERC Board of Trustees</u>     | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Table I. Transmission System Standards – Normal and Emergency Conditions

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

## Standard TPL-004-0(i)a — System Performance Following Extreme BES Events

|   |  |  |
|---|--|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant <del>Special Protection System (or remedial action scheme)</del> Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|---|--|--|

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.



More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

## Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

## Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## Standard TPL-004-0(i)a — System Performance Following Extreme BES Events

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

**Exhibit C**  
**Implementation Plan**

# Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## Project 2010-05.2 – Special Protection Systems

### Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: “An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.”

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

### Requested Approvals

Definition of “**Remedial Action Scheme**” and the standards listed below

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of “Remedial Action Scheme” becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

|                 |                |                |
|-----------------|----------------|----------------|
| CIP-002-3(i)    | PRC-004-WECC-2 | PRC-020-2      |
| CIP-002-3(ii)b  | PRC-005-2(ii)  | PRC-021-2      |
| EOP-004-3       | PRC-005-3(ii)  | PRC-023-2(i)   |
| FAC-010-3       | PRC-006-1(i)   | PRC-023-4      |
| FAC-011-3       | PRC-012-1      | TOP-005-3a     |
| IRO-005-3.1(i)a | PRC-013-1      | TPL-001-0.1(i) |
| MOD-029-2a      | PRC-014-1      | TPL-002-0(i)b  |
| MOD-030-3       | PRC-015-1      | TPL-003-0(i)b  |
| NUC-001-2.1(i)  | PRC-016-1      | TPL-004-0(i)a  |
| PRC-001-1.1(i)  | PRC-017-1      |                |

### Requested Retirements

|              |                |             |
|--------------|----------------|-------------|
| CIP-002-3    | PRC-004-WECC-1 | PRC-020-1   |
| CIP-002-3b   | PRC-005-2      | PRC-021-1   |
| EOP-004-2    | PRC-005-3      | PRC-023-2   |
| FAC-010-2.1  | PRC-006-1      | PRC-023-3   |
| FAC-011-2    | PRC-012-0      | TOP-005-2a  |
| IRO-005-3.1a | PRC-013-0      | TPL-001-0.1 |
| MOD-029-1a   | PRC-014-0      | TPL-002-0b  |
| MOD-030-02   | PRC-015-0      | TPL-003-0b  |
| NUC-001-2.1  | PRC-016-0.1    | TPL-004-0a  |
| PRC-001-1.1  | PRC-017-0      |             |

### General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

### **Prerequisite Approvals**

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding

Definition of “Undervoltage Load Shedding Program (UVLS Program)” in Project 2008-02 Undervoltage Load Shedding

### **Revisions to the NERC Glossary of Terms**

The drafting team proposes the following revised definition:

#### **Remedial Action Scheme (RAS)**

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated



- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

### **Conforming Changes to Other Standards**

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

### **Effective Date for Revised Reliability Standards and Definition**

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### **Implementation Plan for Newly Classified Remedial Action Schemes (RAS)**

Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

**Retirement of Existing Standards and Definitions**

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of “Remedial Action Scheme” shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of “Remedial Action Scheme”.

**Exhibit D**  
**Order No. 672 Criteria**

## EXHIBIT D

### Order No. 672 Criteria

In Order No. 672, the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest.<sup>1</sup> The discussion below identifies these factors and explains how the proposed definition for “Remedial Action Scheme” (Exhibit A) and the Proposed Reliability Standards (Exhibit B) have met or exceeded the criteria.

**1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.<sup>2</sup>**

The proposed definition of Remedial Action Scheme and the associated changes in the Proposed Reliability Standard from use of “Special Protection System” to “Remedial Action Scheme” achieve the specific reliability goal of providing specificity and clarity needed to consistently identify and classify Remedial Action Schemes. The revisions reduce confusion over use of both Special Protection System and Remedial Action Scheme and will reduce regional differences in how various Regions classify Remedial Action Schemes. Further, the revisions include the addition of technical objectives and classification criteria for consistent identification of Remedial Action Schemes. The design of the definition of Remedial Action Schemes is technically sound because it has been structured to capture systems at a broad level, further refine the list through application of specific objectives a Remedial Action Scheme is intended to meet, and even further refined through the explicit inclusion of systems that do not

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

<sup>2</sup> Order No. 672 at PP 321, 324.

individually constitute a Remedial Action Scheme. By taking this approach to the proposed definition, the standard drafting team avoided the possibility of missing classification of a system by use of a narrow and targeted definition.

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

The Proposed Reliability Standards continue to apply to the same applicable entities as the prior versions. By improving the definition of Remedial Action Scheme and replacing uses of Special Protection System with Remedial Action Scheme, NERC has improved the clarity in each of the Proposed Reliability Standards on what is required with respect to Remedial Action Schemes.

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

The VRFs and VSLs for the proposed Reliability Standard did not change as a result of the proposed revisions to the definition and the associated changes to the Proposed Reliability Standards. Accordingly, the VRFs and VSLs for each of the standards continue to comport with NERC and Commission guidelines related to their assignment and include clear and understandable consequences in accordance with Order No. 672.

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

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<sup>3</sup> Order No. 672 at PP 322, 325.

<sup>4</sup> Order No. 672 at P 327.

<sup>5</sup> Order No. 672 at P 328.

Revisions to the Proposed Reliability Standards did not include any substantive revisions to the Measures in any of the Reliability Standards. The existing Measures continue to help provide clarity regarding how the requirements will be enforced, and they continue to help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

**5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect “best practices” without regard to implementation cost or historical regional infrastructure design.<sup>6</sup>**

The proposed definition and revisions to the Proposed Reliability Standards achieve the reliability goal of providing clarity and specificity to the identification and classification of protective schemes effectively and efficiently in accordance with Order No. 672. As a result, the proposed definition will reduce or eliminate misapplication of Reliability Standards that reference Remedial Action Scheme. Also, by changing or removing references to Special Protection System and replacing them with Remedial Action Scheme, the proposed revisions will provide consistency in identification and classification of Remedial Action Schemes continent-wide. This will create efficiency in the application and of the Reliability Standards that utilize the phrase Remedial Action Scheme.

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

The proposed definition and revisions to the Proposed Reliability Standards do not

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<sup>6</sup> Order No. 672 at P 328.

<sup>7</sup> Order No. 672 at P 329-30.

reflect a “lowest common denominator” approach. To the contrary, the proposed definition of Remedial Action Scheme represents an improvement over the current definitions of Special Protection System and Remedial Action Scheme, which lack clarity and specificity. The proposed definition was informed by a comprehensive review by NERC’s System Protection and Control Subcommittee of the definition of Special Protection System and related Reliability Standards that use the term. The standard drafting team fully evaluated this input and posted the strawman definition for industry comment. The standard drafting team also provided analysis in the RAS FAQ document on any differences between the standard drafting team’s approach and the recommendations in the SPCS Technical Report.

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

The proposed RAS definition and Proposed Reliability Standards continue to apply in the same manner as the currently effective Reliability Standards.

- 8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.<sup>9</sup>**

The proposed RAS definition and the revisions to the SPS/RAS Standards will not cause

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<sup>8</sup> Order No. 672 at P 331.

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

undue negative effect on competition or result in any unnecessary restrictions.

**9. The implementation time for the proposed Reliability Standard is reasonable.<sup>10</sup>**

The suggested effective dates for the proposed definition and Reliability Standards are just and reasonable. NERC proposes an effective date of the first day of the first calendar quarter that is twelve (12) months after approval. This period will allow time for entities to review current systems and make any necessary adjustments in their internal processes necessary to implement the proposed the new definition and related Reliability Standards based on the increased granularity of the proposed definition. For entities with newly classified Remedial Action Schemes resulting from the application of the revised definition as explained in this Petition, NERC proposes an effective date of twenty-four months (24) from the Effective Date of the revised definition. While NERC does not anticipate any such changes, the standard drafting team included the additional time in the event a system did encounter a change in status based on the proposed definition. The proposed implementation plan is attached as **Exhibit C**.

**10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.<sup>11</sup>**

The proposed definition and Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards.<sup>12</sup> Exhibit H includes a summary of the development proceedings and details the processes followed to develop the proposed definition and Reliability Standards.

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<sup>10</sup> Order No. 672 at P 333.

<sup>11</sup> Order No. 672 at P 334.

<sup>12</sup> See NERC *Rules of Procedure*, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).



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

**11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.<sup>13</sup>**

NERC has identified no competing public interests regarding the request for approval of the proposed RAS definition and the SPS/RAS Standards. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

**12. Proposed Reliability Standards must consider any other appropriate factors.<sup>14</sup>**

No other factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

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<sup>13</sup> Order No. 672 at P 335.

<sup>14</sup> Order No. 672 at P 323.

**Exhibit E**

*Uses of “Special Protection System” and Remedial Action Scheme” in Reliability Standards*

# Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards

This document provides a summary of the occurrences of “Special Protection System” (“SPS”) and “Remedial Action Scheme” (“RAS”) in the existing NERC Reliability Standards to assist entities in assessing the impact of the proposed definition of “Remedial Action Scheme.” The existing Reliability Standards and certain NERC Glossary of Terms use the terms interchangeably.<sup>1</sup> Changes are proposed in this Project for each applicable standard and NERC Glossary term to align the use of the terminology in each instance. Where only the term SPS occurs, it was replaced with RAS. Where both terms, SPS and RAS, occur, the drafting team deleted the references to SPS. Where only the term RAS occurs, no change was made. In all cases, entities should apply the proposed definition of RAS to its own schemes, and determine any impact.

## General Description of Definition Change

The revised definition of RAS will create one definition to replace both existing definitions in the NERC Glossary of Terms, for use throughout the NERC Reliability Standards. The revised definition of RAS addresses ambiguities within the existing definition and provides clarity to promote consistency in the application of the standards by the responsible entities and the auditing of the standards by compliance staff. The revised definition of RAS recasts the existing definition of SPS to:

- more precisely describe the objectives of the schemes;
- more precisely describe exclusions;
- state the relationship between Protection Systems and RAS; and
- clarify that centrally controlled undervoltage-based load shedding is included in the definition.

## Uses of SPS and RAS in Existing Reliability Standards and NERC Glossary of Terms

The table below includes each occurrence of SPS and RAS found in the applicability sections, requirements, tables, and attachments of the existing NERC Reliability Standards (as of May 16, 2014). The table does not reflect any associated occurrences in other sections of the standard such as the measures, compliance information, and Violation Severity Levels. All occurrences have been reflected in the separate document *Revised Reliability Standards for the Revised Definition of “Remedial Action Scheme.”*

<sup>1</sup> NERC, *Reliability Standards for the Bulk Electric Systems of North America* (Updated December 10, 2014).

| Standard No.  | Existing Standard Language  |   |  |   |         |   |
|---|---|---|--|---|---------|---|
| <p>CIP-002-3<br/>CIP-002-3b</p>                         | <p><b>B. Requirements</b></p> <p><b>R1.</b> Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.</p> <p style="padding-left: 40px;"><b>R1.1.</b> The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.</p> <p style="padding-left: 40px;"><b>R1.2.</b> The risk-based assessment shall consider the following assets:</p> <p style="padding-left: 80px;"><b>R1.2.6.</b> <b>Special Protection Systems</b> that support the reliable operation of the Bulk Electric System.</p>  |   |  |   |         |   |
| <p>EOP-004-2</p>  | <p><b>Attachment 1: Reportable Events</b></p> <table border="1" data-bbox="363 743 1489 900"> <tr> <td data-bbox="363 743 807 900">BES Emergency resulting in automatic firm load shedding</td> <td data-bbox="807 743 912 900">DP, TOP</td> <td data-bbox="912 743 1489 900">Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <b>SPS/RAS</b>).</td> </tr> </table>  |   |  | BES Emergency resulting in automatic firm load shedding | DP, TOP | Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <b>SPS/RAS</b> ). |
| BES Emergency resulting in automatic firm load shedding | DP, TOP   | Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <b>SPS/RAS</b> ). |  |   |         |   |
| <p>FAC-010-2.1</p>                                      | <p><b>B. Requirements</b></p> <p><b>R3.</b> The Planning Authority’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:</p> <p style="padding-left: 40px;"><b>R3.4.</b> Allowed uses of <b>Special Protection Systems</b> or <b>Remedial Action Plans</b>.</p> <p><b>E. Regional Differences</b></p> <p style="padding-left: 40px;"><b>1.1.</b> As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:</p> <p style="padding-left: 80px;"><b>1.1.4</b> The failure of a circuit breaker associated with a <b>Special Protection System</b> to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.</p> |   |  |   |         |   |
| <p>FAC-011-2</p>  | <p><b>B. Requirements</b></p> <p><b>R3.</b> The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:</p> <p style="padding-left: 40px;"><b>R3.5.</b> Allowed uses of <b>Special Protection Systems</b> or <b>Remedial Action Plans</b>.</p> <p><b>E. Regional Differences</b></p> <p style="padding-left: 40px;"><b>1.1.</b> As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:</p> <p style="padding-left: 80px;"><b>1.1.4</b> The failure of a circuit breaker associated with a <b>Special Protection System</b> to operate when required following: the loss of any element without a Fault; or a</p>   |   |  |   |         |   |

| Standard No.               | Existing Standard Language  |
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|                            | <p>permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.</p>  |
| <p><b>IRO-005-3.1a</b></p> | <p><b>B. Requirements:</b></p> <p><b>R1.</b> Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:</p> <p style="padding-left: 40px;"><b>R1.1.</b> Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and <b>Special Protection Systems</b>) and system loading.</p> <p><b>R9.</b> Whenever a <b>Special Protection System</b> that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that <b>Special Protection System</b> on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the <b>Special Protection System</b> including any degradation or potential failure to operate as expected.</p> |
| <p><b>MOD-029-1a</b></p>   | <p><b>B. Requirements</b></p> <p style="padding-left: 40px;"><b>R1.1.8.</b> Uses <b>Special Protection System (SPS)</b> models where currently existing or projected for implementation within the studied time horizon.</p> <p style="padding-left: 40px;"><b>R2.2.</b> Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a <b>Special Protection System (SPS)</b>, set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a <b>SPS</b>.</p>  |
| <p><b>MOD-030-02</b></p>   | <p><b>B. Requirements</b></p> <p style="padding-left: 40px;"><b>R2.1.1.1.</b> Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of <b>Special Protection Systems</b>.</p> <p style="padding-left: 40px;"><b>R2.1.2.1.</b> Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of <b>Special Protection Systems</b>.</p>   |
| <p><b>NUC-001-2.1</b></p>  | <p><b>B. Requirements</b></p> <p><b>R9.</b> The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2:</p> <p style="padding-left: 40px;"><b>R9.3.7.</b> Coordination of the NPIRs with transmission system <b>Special Protection Systems</b> and underfrequency and undervoltage load shedding programs.</p>  |
| <p><b>PRC-001-1.1</b></p>  | <p><b>B. Requirements</b></p>   |

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|   | <p><b>R6.</b> Each Transmission Operator and Balancing Authority shall monitor the status of each <b>Special Protection System</b> in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.</p>   |
| <p><b>WECC Regional Standard PRC-004-WECC-1</b></p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Protection System and <b>Remedial Action Scheme</b> Misoperation</p> <p><b>2. Number:</b> PRC-004-WECC-1</p> <p><b>3. Purpose:</b> Regional Reliability Standard to ensure all transmission and generation Protection System and <b>Remedial Action Scheme (RAS)</b> Misoperations on Transmission Paths and <b>RAS</b> defined in section 4 are analyzed and/or mitigated.</p> <p><b>4. Applicability</b></p> <p><b>4.1.</b>Transmission Owners of selected WECC major transmission path facilities and <b>RAS</b> listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf</a> and “Major WECC <b>Remedial Action Schemes (RAS)</b>” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf</a>.</p> <p><b>4.2.</b>Generator Owners that own <b>RAS</b> listed in the Table titled “Major WECC <b>Remedial Action Schemes (RAS)</b>” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf</a>.</p> <p><b>4.3.</b>Transmission Operators that operate major transmission path facilities and <b>RAS</b> listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf</a> and “Major WECC <b>Remedial Action Schemes (RAS)</b>” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf</a>.</p> <p><b>B. Requirements</b></p> <p>The requirements below only apply to the major transmission paths facilities and <b>RAS</b> listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC <b>Remedial Action Schemes (RAS)</b>.”</p> <p><b>R1.1.</b> System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and <b>RAS</b> operations. <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]</i></p> <p><b>R1.1.1.</b> System Operators shall review all tripping of transmission elements and <b>RAS</b> operations to identify apparent Misoperations within 24 hours.</p> |

| Standard No. | Existing Standard Language  |
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|              | <p><b>R1.2.</b> System Protection personnel shall analyze all operations of Protection Systems and <b>RAS</b> within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.</p> <p><b>R.2.</b> Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or <b>RAS</b>. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or <b>RAS</b> actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or <b>RAS</b> operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:</p> <p><b>R2.1.</b> If the Protection System or <b>RAS</b> has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent <b>RAS</b> (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or <b>RAS</b> that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or <b>RAS</b> is at the Transmission Owners’ and Generator Owners’ discretion.</p> <p><b>R2.2.</b> If the Protection System or <b>RAS</b> has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following.</p> <p><b>R2.2.1.</b> Following identification of the Protection System or <b>RAS</b> Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or <b>RAS</b> that misoperated.</p> <p><b>R2.2.2.</b> The Transmission Owner or Generator Owner shall repair or replace any Protection System or <b>RAS</b> that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the <b>RAS</b> if repair or replacement is not completed within 20 business days.</p> <p><b>R2.3.</b> If the Protection System or <b>RAS</b> has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or <b>RAS</b> that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following.</p> <p><b>R2.3.1.</b> When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.</p> <p><b>R2.3.2.</b> When FERAS is not available, then</p> <p><b>2.3.2.1.</b> The Generator Owners shall adjust generation to a reliable</p> |

| Standard No.   | Existing Standard Language   |
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|  | <p>operating level, or</p> <p><b>2.3.2.2.</b> Transmission Operators shall adjust the SOL and operate the facilities within established limits.</p> <p><b>R2.4.</b> If the Protection System or <b>RAS</b> has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or <b>RAS</b> that failed, provided one of the following is performed.</p> <p><b>R2.4.1.</b> Transmission Owners or Generator Owners shall repair or replace any Protection System or <b>RAS</b> that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or</p> <p><b>R2.4.2.</b> Transmission Owners or Generator Owners shall remove from service the associated Element or <b>RAS</b>. [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Assessment</i>]</p> <p><b>R.3.</b> Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following.</p> <p><b>R3.1.</b> Identification of a Misoperation of a Protection System and/or <b>RAS</b>,</p> <p><b>R3.2.</b> Completion of repairs or the replacement of Protection System and/or <b>RAS</b> that misoperated.</p> |
| PRC-005-2  | <p><b>4. Applicability:</b></p> <p><b>4.2.4</b> Protection Systems installed as a <b>Special Protection System (SPS)</b> for BES reliability.</p>  |
| PRC-005-2 Table 1-4(a) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-2 Table 1-4(b) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-2 Table 1-4(c) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).   |
| PRC-005-2 Table 1-4(d) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).   |
| PRC-005-2 Table 1-4(e) header and Component Attributes                         | <p>Component Type - Protection System Station dc Supply for non-BES Interrupting Devices for <b>SPS</b>, non-distributed UFLS, and nondistributed UVLS systems</p> <p>Component Attributes: Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <b>SPS</b>, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).</p>  |
| PRC-005-2 Table 1-5 header and Component Attributes and Maintenance Activities | <p>Component Type - Control Circuitry Associated With Protective Functions</p> <p>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <b>SPSs</b> except as noted.</p> <p>Component Attributes: Unmonitored control circuitry associated with <b>SPS</b>.</p> <p>Maintenance Activities: Verify all paths of the control circuits essential for proper operation of the <b>SPS</b>.</p>  |



| Standard No.   | Existing Standard Language  |
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|  | Component Attributes: Control circuitry associated with protective functions and/or <b>SPS</b> whose integrity is monitored and alarmed (See Table 2).  |
| PRC-005-3  | <p><b>4. Applicability:</b></p> <p><b>4.2.4</b> Protection Systems installed as a <b>Special Protection System (SPS)</b> for BES reliability.</p> <p><b>4.2.6.3</b> Automatic Reclosing applied as an integral part of an <b>SPS</b> specified in Section 4.2.4.</p>  |
| PRC-005-3 Table 1-4(a) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).   |
| PRC-005-3 Table 1-4(b) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).   |
| PRC-005-3 Table 1-4(c) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-3 Table 1-4(d)   | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-3 Table 1-4(e)   | <p>Component Type - Protection System Station dc Supply for non-BES Interrupting Devices for <b>SPS</b>, non-distributed UFLS, and non-distributed UVLS systems.</p> <p>Component Attributes: Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <b>SPS</b>, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).</p>   |
| PRC-005-3 Table 1-5 header and Component Attributes and Maintenance Activities | <p>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <b>SPSs</b> except as noted.</p> <p>Component Attributes: Unmonitored control circuitry associated with <b>SPS</b> (See Table 4-2(b) for <b>SPS</b> which include Automatic Reclosing.)</p> <p>Maintenance Activities: Verify all paths of the control circuits essential for proper operation of the <b>SPS</b></p> <p>Component Attributes: Control circuitry associated with protective functions and/or <b>SPS</b> whose integrity is monitored and alarmed (See Table 2).</p> |
| PRC-005-3 Table 4-2(a) header and Component Attributes                         | <p>Component Type - Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an <b>SPS</b></p> <p>Component Attributes: Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an <b>SPS</b></p> <p>Component Attributes: Control circuitry associated with Automatic Reclosing that is not part of an <b>SPS</b> and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)</p>   |
| PRC-005-3 Table 4-2(b) header and Component Attributes and                     | <p>Component Type - Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an <b>SPS</b></p> <p>Component Attributes: Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an <b>SPS</b> (regardless of any monitoring of the control circuitry).</p>  |

| Standard No.                         | Existing Standard Language   |
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| <p><b>Maintenance Activities</b></p> | <p>Component Attributes: Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an <b>SPS</b>.</p> <p>Maintenance Activities: Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the <b>SPS</b>.</p> <p>Component Attributes: Control circuitry associated with Automatic Reclosing that is an integral part of an <b>SPS</b> whose integrity is monitored and alarmed. (See Table 2)</p>  |
| <p><b>PRC-012-0</b></p>              | <p><b>A. Introduction</b></p> <p><b>1.</b> Title: <b>Special Protection System</b> Review Procedure</p> <p><b>3.</b> Purpose: To ensure that all <b>Special Protection Systems (SPS)</b> are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <hr/> <p><b>B. Requirements</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an <b>SPS</b> shall have a documented Regional Reliability Organization <b>SPS</b> review procedure to ensure that <b>SPSs</b> comply with Regional criteria and NERC Reliability Standards. The Regional <b>SPS</b> review procedure shall include:</p> <ul style="list-style-type: none"> <li><b>R1.1.</b> Description of the process for submitting a proposed <b>SPS</b> for Regional Reliability Organization review.</li> <li><b>R1.2.</b> Requirements to provide data that describes design, operation, and modeling of an <b>SPS</b>.</li> <li><b>R1.3.</b> Requirements to demonstrate that the <b>SPS</b> shall be designed so that a single <b>SPS</b> component failure, when the <b>SPS</b> was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</li> <li><b>R1.4.</b> Requirements to demonstrate that the inadvertent operation of an <b>SPS</b> shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.</li> <li><b>R1.5.</b> Requirements to demonstrate the proposed <b>SPS</b> will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.</li> <li><b>R1.7.</b> Requirements for analysis and documentation of corrective action plans for all <b>SPS</b> misoperations.</li> </ul> <p><b>R2.</b> The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its <b>SPS</b> review procedure on request (within 30 calendar days).</p> |

| Standard No.     | Existing Standard Language  |
|------------------|---|
| <p>PRC-013-0</p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Special Protection System Database.</p> <p><b>3. Purpose:</b> To ensure that all Special Protection Systems (SPSs) are properly designed, meet performance requirements, and are coordinated with other protection systems.</p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:</p> <ul style="list-style-type: none"> <li><b>R1.1.</b> Design Objectives — Contingencies and system conditions for which the SPS was designed,</li> <li><b>R1.2.</b> Operation — The actions taken by the SPS in response to Disturbance conditions, and</li> <li><b>R1.3.</b> Modeling — Information on detection logic or relay settings that control operation of the SPS.</li> </ul>   |
| <p>PRC-014-0</p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Special Protection System Assessment</p> <p><b>3. Purpose:</b> To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria</p> <p><b>R2.</b> The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).</p> <p><b>R3.</b> The documentation of the Regional Reliability Organization’s SPS assessment shall include the following elements:</p> <ul style="list-style-type: none"> <li><b>R3.3.</b> Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.</li> <li><b>R3.4.</b> Discussion of any coordination problems found between a SPS and other protection and control systems.</li> <li><b>R3.5.</b> Provide corrective action plans for non-compliant SPSs.</li> </ul> |

| Standard No.     | Existing Standard Language   |
|------------------|--|
| <p>PRC-015-0</p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Special Protection System Data and Documentation</p> <p><b>3. Purpose:</b> To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>4. Applicability:</b></p> <p><b>4.1.</b> Transmission Owner that owns an SPS</p> <p><b>4.2.</b> Generator Owner that owns an SPS</p> <p><b>4.3.</b> Distribution Provider that owns an SPS</p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.</p> <p><b>R2.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.</p> <p><b>R3.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).</p> |

| Standard No.       | Existing Standard Language  |
|--------------------|---|
| <p>PRC-016-0.1</p> | <p><b>A. Introduction</b></p> <p>1. Title: <b>Special Protection System</b> Misoperations</p> <p>3. Purpose: To ensure that all <b>Special Protection Systems (SPS)</b> are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>4. Applicability:</b></p> <p>4.1. Transmission Owner that owns an <b>SPS</b></p> <p>4.2. Generator Owner that owns an <b>SPS</b></p> <p>4.3. Distribution Provider that owns an <b>SPS</b></p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall analyze its <b>SPS</b> operations and maintain a record of all misoperations in accordance with the Regional <b>SPS</b> review procedure specified in Reliability Standard PRC-012-0_R1.</p> <p><b>R2.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall take corrective actions to avoid future misoperations.</p> <p><b>R3.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).</p> |

| Standard No.                       | Existing Standard Language  |
|------------------------------------|---|
| <p>PRC-017-0</p>                   | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> <b>Special Protection System</b> Maintenance and Testing</p> <p><b>3. Purpose:</b> To ensure that all <b>Special Protection Systems (SPS)</b> are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>4. Applicability:</b></p> <p><b>4.1.</b> Transmission Owner that owns an <b>SPS</b></p> <p><b>4.2.</b> Generator Owner that owns an <b>SPS</b></p> <p><b>4.3.</b> Distribution Provider that owns an <b>SPS</b></p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <p style="padding-left: 40px;"><b>R1.1.</b> <b>SPS</b> identification shall include but is not limited to:</p> <p><b>R2.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).</p> |
| <p>PRC-020-1</p>                   | <p><b>B. Requirements</b></p> <p><b>R1.6.</b> Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and <b>Special Protection Systems</b>.</p>  |
| <p>PRC-021-1</p>                   | <p><b>B. Requirements</b></p> <p><b>R1.5.</b> Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and <b>Special Protection Systems</b>.</p>  |
| <p>TOP-005-2a<br/>Attachment 1</p> | <p><b>Electric System Reliability Data</b></p> <p>This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.</p> <p style="padding-left: 40px;"><b>2.6.</b> New or degraded <b>Special Protection Systems</b>.</p>   |
| <p>TPL-001-0.1<br/>Category D</p>  | <p><b>Table 1. Transmission System Standards - Normal and Emergency Conditions</b></p> <p><b>12.</b> Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p><b>13.</b> Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p>   |

| Standard No.                                   | Existing Standard Language  |
|--|---|
| <p><b>TPL-002-0b</b><br/><b>Category D</b></p> | <p><b>Table I. Transmission System Standards — Normal and Emergency Conditions</b></p> <p>12. Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p> |
| <p><b>TPL-003-0b</b><br/><b>Category D</b></p> | <p><b>Table I. Transmission System Standards — Normal and Emergency Conditions</b></p> <p>12. Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p> |
| <p><b>TPL-004-0a</b><br/><b>Category D</b></p> | <p><b>Table I. Transmission System Standards — Normal and Emergency Conditions</b></p> <p>12. Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p> |
| <p><b>WECC Regional Glossary Term:</b></p>     | <p><b>Definition: Dependability-Based Misoperation</b></p> <p>Is the absence of a Protection System or <b>RAS</b> operation when intended. Dependability is a component of reliability and is the measure of a device’s certainty to operate when required.</p>   |
| <p><b>WECC Regional Glossary Term:</b></p>     | <p><b>Definition: Functionally Equivalent RAS (FERAS)</b></p> <p>A <b>Remedial Action Scheme ("RAS")</b> that provides the same performance as follows:</p> <ul style="list-style-type: none"> <li>• Each <b>RAS</b> can detect the same conditions and provide mitigation to comply with all Reliability Standards.</li> <li>• Each <b>RAS</b> may have different components and operating characteristics</li> </ul>  |
| <p><b>WECC Regional Glossary Term:</b></p>     | <p><b>Definition: Security-Based Misoperation</b></p> <p>A Misoperation caused by the incorrect operation of a Protection System or <b>RAS</b>. Security is a component of reliability and is the measure of a device’s certainty not to operate falsely.</p>   |

**Exhibit F**

*“Remedial Action Scheme” Definition Development: Background and Frequently Asked Questions*



**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# “Remedial Action Scheme” Definition Development Background and Frequently Asked Questions

Project 2010-05.2 – Special Protection Systems

October 2014

**RELIABILITY | ACCOUNTABILITY**



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## Introduction

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The Project 2010-05.2 – Special Protection Systems Standard Drafting Team (SDT) developed this background and Frequently Asked Questions (FAQ) document to explain the key concepts incorporated into the revised definition, as well as the team’s approach and intent. This document will remain available as part of the official project record for the Remedial Action Scheme (RAS) definition. The drafting team has updated this (FAQ) document to reflect all revisions made to the RAS definition based on stakeholder feedback.

Contact the Standards Developer, Al McMeekin, at 404-446-9675 or at [al.mcmeekin@nerc.net](mailto:al.mcmeekin@nerc.net) with any comments or questions.

## Background and FAQ – RAS Definition Development

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### Existing Glossary of Terms Used in NERC Reliability Standards Definitions

The existing Glossary of Terms Used in NERC Reliability Standards defines **SPS** or **RAS** as: “An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.”

The Glossary of Terms Used in NERC Reliability Standards defines a **Protection System** as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

### Revision of the Glossary of Terms Used in NERC Reliability Standards Definition

#### Purpose of Revision of the Glossary of Terms Used in NERC Reliability Standards SPS or RAS

The existing Glossary of Terms Used in NERC Reliability Standards definition for an SPS/RAS lacks the clarity and specificity necessary to consistently identify what equipment or schemes qualify as an SPS/RAS across the eight NERC Regions. This confusion leads to inconsistent application of the SPS/RAS-related NERC Reliability Standards.

The existing definition also lacks clarity in the actions stipulated as characteristics of an SPS/RAS. The actions listed in the definition are so broad that the definition may unintentionally include schemes whose purpose is not expressly related to preserving system reliability in response to predetermined system conditions. Inclusion of any scheme taking “corrective action other than isolation of faulted components to maintain system reliability” could be interpreted to mean that devices such as voltage regulators and switching controls for shunt capacitors should be included. This inclusion would then make these devices subject to requirements such as those addressing single-component failure considerations (sometimes referred to as redundancy considerations) in the SPS/RAS-related NERC Reliability Standards.

#### Recommendation to Change the Term to RAS Only

Currently, both terms, SPS and RAS, are used in the eight NERC Regions. The SDT contends that a single term promotes consistency. The SDT therefore recommends that the term RAS be retained as the industry-recognized term and that the term SPS ultimately be retired. The term RAS is more descriptive of the purpose for which the scheme is installed.

The term RAS also eliminates the confusion associated with the two defined terms, “Special Protection System” and “Protection System.” The inclusion of Protection System in the term Special Protection System implies that SPS are a subset of Protection Systems.

### Effects of Using Only the Term RAS in the Existing NERC Reliability Standards

The existing NERC Reliability Standards and Glossary of Terms Used in NERC Reliability Standards use the terms, SPS and RAS interchangeably. In most cases, both terms are included in the standards and written as: “SPS or RAS.” The SDT evaluated the existing standards and recommended any necessary revisions to retain the single term “RAS”. Many of the same changes would be required regardless of which single term is retained. A summary of the occurrences of the terms is included in the posted document *Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards*.

## Proposed Definition of RAS

**Remedial Action Scheme:** A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Exclusion List Explanations

**a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes the isolation of faulted components because that is a protective function. Protection Systems installed for the purpose of detecting Faults on non-BES Elements are not RAS, and are not subject to NERC Reliability Standards. The SDT accepts this exclusion consistent with industry practice.

**b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes UFLS and UVLS because they are protective functions that have unique design and implementation considerations that are covered by NERC Reliability Standards PRC-006-1 and PRC-010-1. This exclusion emphasizes “distributed” UVLS relays to highlight that the exclusion covers UVLS Programs. The SDT accepts this exclusion consistent with industry practice.

Centrally controlled undervoltage-based load shedding is a RAS.

**c. Out-of-step tripping and power swing blocking**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes out-of-step relaying because it is a protective function. The SDT maintained the exclusion but changed the wording from “out-of-step relaying” to “out-of-step tripping and power swing blocking” to reflect current industry terminology.

**d. Automatic reclosing schemes**

Automatic reclosing schemes, whether single-pole or three-pole, are used to minimize system impacts and restoration efforts by System Operators. Automatic reclosing, in itself, is not a RAS; however, if integrated into a larger scheme that performs additional corrective actions to accomplish the objective(s) listed in the RAS definition, then it would be part of a RAS. For example, a scheme that rejects or runs back generation to avoid instability or thermal overloads in addition to initiating automatic reclosing would constitute a RAS. The drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) automatic reclosing schemes. Automatic reclosing schemes that restore load to an alternate source would typically not be a RAS; however, system reconfiguration which transfers the load to another source for purposes other than load restoration typically would be a RAS.

**e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service**

Schemes applied on a single Element to protect it from damage from non-Fault conditions are protective functions and are not RAS. Other examples of schemes that would qualify within this exclusion are reverse power, volts/hertz, winding temperature, and loss of cooling. The SDT accepts this exclusion consistent with industry practice.

- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated**

Controllers that switch or regulate these devices are not RAS. The SDT accepts this exclusion consistent with industry practice. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations.

- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device**

The purpose of such controllers is to switch shunt devices to restore an acceptable operating range of a single FACTS device. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations. The SDT accepts this exclusion consistent with industry practice.

- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched**

Schemes or controllers that assist a System Operator in coordinating the switching of shunt reactors and shunt capacitors that would otherwise be manually switched are not remedial in the sense of being mitigations in response to predetermined System conditions, but are for general application to all System conditions, e.g. optimizing voltage profiles or minimizing losses. The SDT accepts this exclusion consistent with industry practice.

- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open**

When one end of a line is open, unacceptable voltage levels can occur. Opening the remote terminal(s) to de-energize the transmission line removes this voltage rise. Alternatively, restoration conditions may require energization or synchronizing at a specific terminal. These schemes have not historically been regarded as RAS, and the SDT accepts this exclusion consistent with industry practice.

- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)**

These schemes are designed to protect load in an electrical island that might otherwise operate at an off-nominal frequency or voltage, or facilitate restoration. Actions taken on islanded facilities will not impact the interconnected BES because the facilities are isolated. The SDT accepts this exclusion consistent with industry practice.

- k. Automatic sequences that proceed when manually initiated solely by a System Operator**

Automated sequences created to simplify the actions of a System Operator are not RAS because the decision to activate a specific sequence is left to the System Operator. If the automated sequence fails to execute correctly, the System Operator has the option to manually set those actions in motion. The SDT accepts this exclusion consistent with industry practice.

The arming of a RAS by a System Operator is not the same as manual initiation of an automatic sequence. Arming enables the scheme but the RAS must still detect the critical conditions it was designed to mitigate and then take action.

**l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations**

Modulation of HVdc and FACTS via supplementary controls is occasionally used for damping local or inter-area oscillations. It is similar in function to a Power System Stabilizer (PSS), which is a component of excitation controls in a generating unit. PSS are also not classified as RAS. The SDT accepts these HVdc and FACTS exclusions consistent with industry practice.

**m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities; (e.g., currents or torsional oscillations)**

Historically, SSR protection schemes that directly detect sub-synchronous quantities and the related mitigation are not RAS. The SDT accepts this exclusion consistent with industry practice.

However, SSR protection schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

**n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing**

These traditional generator and turbine controls are not RAS. The SDT accepts this exclusion consistent with industry practice.



## Explanations Regarding Changes from the Exclusion List Cited in the SAMS-SPCS Report

The SDT revised the straw man definition proposed in the SAMS-SPCS report; however, the proposed definition is consistent with the SAMS-SPCS intent. As a result of the revisions, it is no longer necessary to explicitly state the following exclusions.

**1. Schemes that prevent high line voltage by automatically switching the affected line**

These schemes are now addressed by exclusion (e) (protection from overvoltage) and exclusion (i) (automatic de-energization of a line when one end is open) in the proposed definition.

**2. Protection schemes that operate local breakers other than those on the faulted circuit to facilitate Fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a Fault or to reduce fault duty**

These schemes are now addressed by exclusion (a) in the proposed definition.

**3. Blanket exclusion for SSR protection schemes**

The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

**4. A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements**

These schemes are now addressed by exclusion (a) in the proposed definition.

## Frequently Asked Questions

### **What is the relationship between a Remedial Action Scheme and a Protection System?**

The existing definition of a Protection System in the Glossary of Terms Used in NERC Reliability Standards is a component-based definition that was developed in conjunction with NERC Reliability Standard PRC-005-2 Protection System Maintenance. The definition lists components such as “protective relays which respond to electrical quantities” that represent the building blocks of a Protection System. All protective schemes include some combination of these building blocks but not necessarily all of them, for example, many protective schemes do not have the “communications systems...” component. In other cases, protective schemes like RAS may have all of the Protection System components as well as other pieces of equipment such as programmable logic controllers.

### **Why does the proposed definition have an exclusion list?**

The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS.

### **Why did the SDT not propose a screening process to identify RAS?**

The SDT contends that a comprehensive definition with specific exclusions is the best way to achieve consistency and immediacy in RAS identification. The SDT asserts that a study-based screening process would be labor-intensive and dependent on assumptions that could vary among the entities performing the studies.

**Why does the proposed definition not include the classification types suggested in the SPCS-SAMS report?**

The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.

**Why did the SDT not specifically reference the Transmission Planning (TPL) standards in the proposed definition?**

The SDT acknowledges that many RAS are installed to address the performance requirements of the TPL standards; however, they are also installed to address other reliability concerns.

**Would automatic actions taken by an Energy Management System (EMS), Supervisory Control and Data Acquisition (SCADA), or Distribution Control System (DCS) be considered a RAS?**

The above-mentioned control systems support and enable grid operations by issuing control commands mostly to geographically distributed power System devices. In this normal application, e.g. automatic generation control (AGC), these systems are not considered to be RAS. However, if these systems are configured to detect predetermined conditions and take corrective actions consistent with the RAS definition, these automatic functions (not the entire EMS) would be considered to be part of a RAS. The identification of RAS is not dependent upon the specific hardware or platform utilized in the scheme. For example, an automatic UVLS scheme centrally controlled through an EMS would be a RAS.

**Would controllers at the terminals of a High Voltage direct current (HVdc) Facility be considered a RAS?**

HVdc terminal controls such as those which maintain proper converter operation, regulate current, voltage or power flow, or that provide protection for the HVdc Facility itself do not meet the definition of RAS. However, an HVdc control scheme designed to take corrective actions based on predetermined System conditions, such as backing down power transfer on an HVdc Facility following a Contingency to avoid overload of another BES Element *would be* part of a RAS.

**Why are local cross-trip schemes RAS?**

Switching in the same substation (including transfer- or cross-trip schemes) to trip Elements other than the protected Element is a System reconfiguration and is therefore a RAS. Reconfiguring the System can be a critical factor in reliability and merits the review and oversight associated with RAS.

**What are the Implementation Plan time frames?**

The effective date of the RAS definition as noted in the Implementation Plan is the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. The drafting team notes that RAS owners could use this time to evaluate their existing schemes for determining whether they are RAS, based on the new definition.

The Implementation Plan also provides owners of newly identified RAS twenty-four (24) calendar months beyond the effective date of the definition (i.e., at least 36 months after approval by a governmental authority) to be fully compliant with the existing standards applicable to the revised definition of Remedial Action Scheme. The drafting team contends that this time frame provide entities sufficient time to transition schemes to RAS and become compliant with the revised standards outlined in the Implementation Plan.

Note: These timeframes are not applicable to new RAS implemented subsequent to the effective date of the new definition. New RAS must comply with all applicable standards as they are implemented.

## **Coordination with Project 2008-02 – Undervoltage Load Shedding**

As part of the development of PRC-010-1, the Project 2008-02 UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1:

**Undervoltage Load Shedding Program (UVLS Program):** An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

Note that the definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintained that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, centrally controlled undervoltage-based load shedding should be subject to RAS-related Reliability Standards.

The Project 2010-05.2 SPS SDT agreed with the Project 2008-02 UVLS SDT that the design and characteristics of centrally controlled undervoltage-based load shedding are more appropriately categorized as RAS. The SPS SDT revised the definition of RAS to clarify that the definition is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. The SDT coordinated this change with the Project 2008-02 UVLS SDT. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as a RAS. As a result, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective date of the revised definition of RAS.

## Attachment A – SDT Members

| Project 2010-05.2 – Special Protection Systems SDT |                                   |                                       |
|--|-----------------------------------|---------------------------------------|
|  | Participant                       | Entity                                |
| Chair  | Gene Henneberg                    | NV Energy / Berkshire Hathaway Energy |
| Vice Chair   | Bobby Jones                       | Southern Company                      |
| Member   | Amos Ang                          | Southern California Edison            |
|  | John Ciufu                        | Hydro One Inc.                        |
|  | Alan Engelmann                    | ComEd / Exelon                        |
|  | Davis Erwin                       | Pacific Gas and Electric              |
|  | Sharma Kolluri                    | Entergy                               |
|  | Charles-Eric Langlois             | Hydro-Quebec TransEnergie             |
|  | Robert J. O'Keefe                 | American Electric Power               |
|  | Hari Singh                        | Xcel Energy                           |
| NERC Staff   | Al McMeekin (Standards Developer) | NERC                                  |
|  | Lacey Ourso (Standards Developer) | NERC                                  |
|  | Phil Tatro (Technical Advisor)    | NERC                                  |
|  | Bill Edwards (Legal Counsel)      | NERC                                  |

**Exhibit G**

**SPCS Technical Report: *Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards***

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards

Revision 0.1 – April 2013

**RELIABILITY | ACCOUNTABILITY**

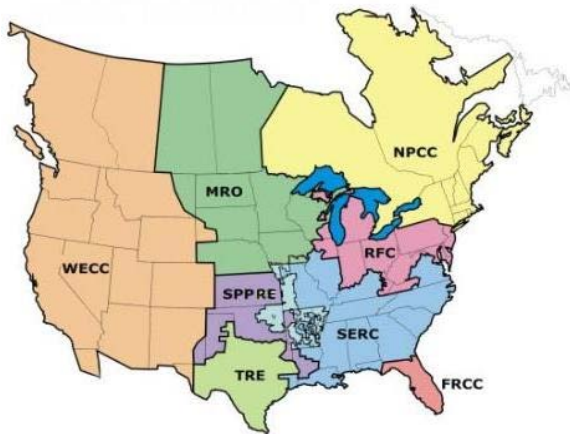


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# NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.<sup>1</sup>

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



**Note:** The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

| NERC Regional Entities                                  |   |
|---|---|
| <b>FRCC</b><br>Florida Reliability Coordinating Council | <b>SERC</b><br>SERC Reliability Corporation             |
| <b>MRO</b><br>Midwest Reliability Organization          | <b>SPP RE</b><br>Southwest Power Pool Regional Entity   |
| <b>NPCC</b><br>Northeast Power Coordinating Council     | <b>TRE</b><br>Texas Reliability Entity                  |
| <b>RFC</b><br>ReliabilityFirst Corporation              | <b>WECC</b><br>Western Electricity Coordinating Council |

<sup>1</sup> As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC’s reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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*This technical document was approved by the NERC Planning Committee on March 5, 2013.*

## Executive Summary

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The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration. A request for research was submitted by the Standards Committee on January 9, 2012 (see Appendix D). The Planning Committee had already approved a joint effort by the System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) <sup>2</sup> on June 8, 2011 (see Appendix E) which includes issues identified in the request for research. This report addresses all issues identified in the scope of the joint SAMS and SPCS project as well as the Standards Committee request for research; upon approval by the Planning Committee the report should be forwarded to the Standards Committee to support Project 2010-05.2.

This report includes recommendations for a new definition of SPS and revisions to the six SPS-related PRC standards. A strawman definition is provided that eliminates ambiguity in the existing definition and identifies 13 types of schemes that are not SPS, but for which uncertainty has existed in the past based on experience within the Regions. The report also recommends that SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed.

This report provides recommendations to address FERC concerns with PRC-012-0, PRC-013-0, and PRC-014-0, which assign requirements to Regional Reliability Organizations. Recommendations are made to reassign requirements to specific users, owners, and operators of the bulk power system to remedy this situation.

Project 2010-05.2 should consolidate the requirements pertaining to review, assessment, and documentation of SPS into one standard that includes continent-wide procedures for reviewing new or modified SPS, for assessing existing SPS in annual transmission planning assessments, and for periodic comprehensive SPS assessments. The project also should revise requirements pertaining to analysis and reporting of SPS misoperations in a revision of standard PRC-016-0.1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004. Given the scope of work and need for drafting team members with different subject matter expertise it may be appropriate to sub-divide Project 2010-05.2 to address review, assessment and documentation of SPS separately from analysis and reporting of misoperations. This report also provides recommendations for Standards Committee consideration that are outside the scope of Project 2010-05.2. These additional recommendations pertain to maintenance and testing and operational aspects of SPS.

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<sup>2</sup> The original scope of work involved the SPCS and the predecessor of SAMS, the Transmission Issues Subcommittee (TIS).

# Introduction

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## Problem Statement

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration.

## Background

### NERC Definitions

The existing NERC *Glossary of Terms* defines an SPS and RAS as:

#### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

In this document, use of the term SPS in general discussions and proposals for future definitions and standards apply to both SPS and RAS. Specific references to existing practices within Regions use the term SPS or RAS as appropriate for that Region.

The NERC *Glossary of Terms* defines a Protection System as:

#### *Protection System*

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Inclusion of the words “protection system” in the term Special Protection System has raised questions whether this is an intentional reference such that SPS are a subset of Protection Systems. Use of protection system (lower case) within the SPS definition identifies that SPS are not Protection Systems. While SPS may include the same types of components as Protection Systems, SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment. SPS may, for example, effect a change to the operating state of power system elements to preserve system stability or to avoid unacceptable voltages or overloads in response to system events. There are many reasons for implementing an SPS; for example, an SPS can be implemented to ensure compliance with the TPL Reliability Standards, to mitigate temporary operating conditions or abnormal configurations (e.g., during construction or maintenance activities), or in instances where system operators would not be able to respond quickly enough to avoid adverse system conditions.

A second area in which the existing SPS definition lacks clarity is the actions that are characteristics of SPS. The actions listed in the definition are broad and may unintentionally include equipment whose purpose is not expressly related to preserving system reliability in response to an event. Inclusion of any system taking “corrective action other than ... isolation of faulted components to maintain system reliability” could be deemed to include equipment such as voltage regulators and switching controls for shunt reactive devices. This inclusion would then make these elements subject to single component failure considerations (sometimes referred to as redundancy considerations), coordination, reporting, and maintenance and testing requirements that may be required in the NERC Reliability Standards related to SPS.

This report proposes a revised definition of SPS to address these issues. Development of the proposed definition considered other definitions, common applications, and existing practices regarding classification of SPS.

### **NERC Reliability Standards**

The NERC Reliability Standards contain six standards in the protection and control (PRC) series that specifically pertain to SPS.

- PRC-012-0: Special Protection System Review Procedure
- PRC-013-0: Special Protection System Database
- PRC-014-0: Special Protection System Assessment
- PRC-015-0: Special Protection System Data and Documentation
- PRC-016-0.1: Special Protection System Misoperations
- PRC-017-0: Special Protection System Maintenance and Testing

Three of these standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*. These standards assign the Regional Reliability Organizations responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of SPS. The deference to regional practices, coupled with lack of clarity in the definition of SPS, preclude consistent application of requirements pertaining to SPS. This report provides recommendations that may be implemented through the NERC Reliability Standards Development Process to consolidate the standards and provide greater consistency and clarity regarding requirements.

# Chapter 1 – SPS Definition

## Considerations for a Revised Definition

### Other Definitions in Industry

Several IEEE papers<sup>3</sup> define a similar term to SPS: System Integrity Protection System (SIPS). Adopting the SIPS definition is not appropriate because it is more inclusive than NERC’s definition:

“The SIPS encompasses special protection system (SPS), remedial action schemes (RAS), as well as other system integrity schemes, such as underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc.”<sup>4</sup>

NERC applies special consideration to UF and UV load shedding schemes in the Reliability Standards and considers OOS relaying in the context of traditional protection systems. Thus, SIPS is not an appropriate term for use in the Reliability Standards, and a new definition of SPS is more appropriate.

### Common Application of SPS in Industry

Most SPS are used to address a range of system issues including stability, voltage, and loading concerns. Less common applications include arresting sub-synchronous resonance and suppressing torsional oscillations. Actions taken by SPS may include (but are not limited to): system reconfiguration, generation rejection or runback, load rejection or shedding, reactive power or braking resistor insertion, and runback or fast ramping of HVdc.

SPS are often deployed because the operational solutions they facilitate are substantially quicker and less expensive to implement than construction of transmission infrastructure. Permanent SPS have been implemented in some cases where the cost associated with system expansion is prohibitive, construction is not possible due to physical constraints, or obtaining permits is not feasible. In other cases temporary SPS have been implemented to maintain system reliability until transmission infrastructure is constructed; or when a reliability risk is temporary (e.g., during equipment outages) and the expense associated with permanent transmission upgrades is not justified.

The deployment of SPS adds complexity to power system operation and planning:

“Although SPS deployment usually represents a less costly alternative than building new infrastructure, it carries with it unique operational elements among which are: (1) risks of failure on demand and of inadvertent activation; (2) risk of interacting with other SPS in unintended ways; (3) increased management, maintenance, coordination requirements, and analysis complexity.”<sup>5</sup>

Subsequent sections of this report consider these three operational elements and provide recommendations regarding how they should be addressed in the NERC Reliability Standards. A summary of the number of schemes identified as SPS or RAS by Region is provided below.

| Region | Total Number | Region | Total Number |
|--------|--------------|--------|--------------|
| FRCC   | 20           | SERC   | 20           |
| MRO    | 36           | SPP    | 6            |
| NPCC   | 117          | TRE    | 24           |
| RFC    | 47           | WECC   | 192          |

<sup>3</sup> One notable reference, Madani, et al, “IEEE PSRC Report on Global Industry Experiences with System Integrity Protection Schemes (SIPS),” IEEE Trans. on Power Delivery, Vol. 25, Oct. 2010.

<sup>4</sup> *Ibid.*

<sup>5</sup> McCalley, et al, “System Protection Schemes: Limitations, Risks, and Management”, PSERC Publication 10-19, Dec 2010.

<sup>6</sup> Numbers for 2011 obtained from data reported in the NERC Reliability Metric ALR6-1.

## Classification of SPS Types

Three regions classify SPS according to various criteria, including the type of event the SPS is designed to address as well as the ability of the SPS to impact on a local versus wide-area reliability. The following information describes how NPCC, WECC and TRE classify SPS. Please note that examples of regional practices are provided for illustration throughout this document, but are not necessarily best practices or applicable to all Regions. Also in this context, what constitutes local versus wide-area varies among Regions and is not based on the NERC glossary term Wide Area, which is specific to calculation of Interconnection Reliability Operating Limits (IROL).<sup>7</sup>

### *NPCC*

**Type I** – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. The corrective action taken by the Special Protection System along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.

**Type II** – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.

**Type III** – A Special Protection System whose misoperation or failure to operate results in no significant adverse impact outside the local area.

The following terms are also defined by NPCC to assess the impact of the SPS for their classification:

**Significant adverse impact** – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

- a. system instability;
- b. unacceptable system dynamic response or equipment tripping;
- c. voltage levels in violation of applicable emergency limits;
- d. loadings on transmission facilities in violation of applicable emergency limits;
- e. unacceptable loss of load.

**Local area** – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

### *WECC*

**Local Area Protection Scheme (LAPS):** A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss  $\geq$  300 MW,
- Maximum generation loss  $\geq$  1000 MW.

---

<sup>7</sup> The NERC Glossary defines Wide Area as “The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.”

**Wide Area Protection Scheme (WAPS):** A Remedial Action Scheme (RAS) whose failure to operate WOULD result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss  $\geq$  300 MW,
- Maximum generation loss  $\geq$  1000 MW.

**Safety Net:** A type of Remedial Action Scheme designed to remediate TPL-004-0 (System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)), or other extreme events.

**TRE:**

- (a) A “Type 1 SPS” is any SPS that has wide-area impact and specifically includes any SPS that:
  - (i) Is designed to alter generation output or otherwise constrain generation or imports over DC Ties; or
  - (ii) Is designed to open 345 kV transmission lines or other lines that interconnect Transmission Service Providers (TSPs) and impact transfer limits.
- (b) A “Type 2 SPS” is any SPS that has only local-area impact and involves only the facilities of the owner-TSP.

These three regional classifications can be roughly mapped:

- NPCC Type I = WECC WAPS = TRE Type 1
- NPCC Type III = WECC LAPS = TRE Type 2
- NPCC Type II = WECC Safety Net

SPS classification differentiates the reliability risk associated with SPS and provides a means to establish more or less stringent requirements consistent with the reliability risk. For example, it may be appropriate to establish less stringent requirements pertaining to monitoring or single component failure of SPS that present a lower reliability risk. A recommendation for classification of SPS is included with the proposed definition and subsequent discussion of standard requirements includes recommendations where different requirements based on classification are deemed appropriate.

**Common Exclusions from the SPS Definition in Industry**

Exclusions provide a means to assure that specific protection or control systems are not unintentionally included as SPS. The NERC glossary definition of SPS states that “An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS).”

Even with the exclusions in the NERC definition, other commonly applied protection and control systems meet the general language in the SPS definition. Considerable effort has been expended by industry discussing what systems are SPS. NPCC and SERC have documented examples of exclusions to the SPS definition in their regional guidelines. NPCC explicitly excludes “Automatic underfrequency load shedding; Automatic undervoltage load shedding and manual or automatic locally controlled shunt devices.”<sup>8</sup> SERC’s SPS guideline calls out specific exclusions as follows:

- a. UFLS and/or UVLS,
- b. Fault conditions that must be isolated including bus breakup / backup / breaker failure protection,
- c. Relays that protect for specific equipment damage (such as overload, overcurrent, hotspot, reclose blocking, etc.),
- d. Out of step relaying,
- e. Capacitor bank / reactor controls,

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<sup>8</sup> NPCC *Glossary of Terms Used by Directories*

- f. Load Tap Changer (LTC) controls,
- g. Automated actions that could be performed by an operator in a reasonable amount of time, including alternate source schemes, and
- h. Scheme that trips generation to prevent islanding

A recommended list of protection and control systems that should be excluded from classification as SPS is included with the proposed definition.

### Exclusion for Operator Aides

SAMS and SPCS considered a number of factors in discussing this subject including:

- 1) whether the actions are required to be completed with such urgency that it would be difficult for an operator to react and execute in the necessary time, and
- 2) whether the required actions are of such complexity or across such a large area that it would be difficult for an operator to perform the actions in the necessary time.

It is difficult to address these questions with concise and measurable terms, making it difficult to explicitly exclude them in the definition without introducing ambiguous terms counter to the objective of providing needed clarity in the SPS definition. Whether its existence is based upon convenience or not, any automated system with the potential to impact bulk power system reliability should be defined and expressed to the appropriate authority (e.g., Planning Coordinator, Reliability Coordinator) for the purposes of system modeling and coordination studies, to ensure that these systems are properly coordinated with other protection and control systems, and to ensure that inadvertent operations do not result in adverse system impacts.

On these bases, SAMS and SPCS decided not to provide an exclusion for schemes based on a general criterion as to whether the scheme automates actions that an operator could perform in a reasonable amount of time or schemes installed for operator convenience. However, SAMS and SPCS do recommend exclusions for specific applications that meet these criteria such as automatic sequences that are initiated manually by an operator. Furthermore, any scheme that is not installed “to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, an extreme event, or Cascading” would be excluded by definition, regardless of whether it is installed to assist an operator.

### Voltage Threshold

All elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.

### Proposed Definition

The proposed definition clarifies the areas that have been interpreted differently between individual entities and within Regions, in some cases leading to differing regional definitions of SPS. The proposed definition provides a framework for differentiating among SPS with differing levels of reliability risk and will support the drafting of new or revised SPS standards.

#### *Special Protection System (SPS)*

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.



The following schemes do not constitute an SPS in and of themselves:

- a) Underfrequency or undervoltage load shedding
- b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature
- c) Autoreclosing schemes
- d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers
- e) Schemes that prevent high line voltage by automatically switching the affected line
- f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open
- g) Out-of-step relaying
- h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty
- j) Automatic sequences that proceed when manually initiated solely by an operator
- k) Sub-synchronous resonance (SSR) protection schemes
- l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards.

- Type PS (planning-significant): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type PL (planning-limited): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.
- Type ES (extreme-significant): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type EL (extreme-limited): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.

An SPS is classified as having a significant impact on the BES if failure or inadvertent operation of the scheme results in any of the following:

- Non-Consequential Load Loss  $\geq$  300 MW

- Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection<sup>9</sup>
- Loss of synchronism between two or more portions of the system each including more than one generating plant
- Negatively damped oscillations

If none of these criteria are met, the SPS is classified as having a limited impact on the BES.

## Definition of Significant and Limited Impact

The parameters used to define the bright line between “significant” and “limited” impacts are proposed to consider only the electrical scale of the event. Defining the bright line in this way eliminates the difficulty in distinguishing the geographic impact of an SPS as either “wide” or “local.”

NERC Standard EOP-004-1, DOE Form OE-417 Electric Emergency Incident and Disturbance Report, establishes the criteria by which an event is categorized as a Disturbance and requires a disturbance report. In terms of SPS, the proposed criteria for significant impact mirrors EOP-004-1 by including a non-consequential load loss value of 300 MW.

NERC Reliability Standards require consideration of loss of any generating unit; therefore, generating unit loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the interconnection. The generation loss level was selected as a loss greater than the largest unit within an interconnection on this basis.

Tripping multiple generating units exceeding the capacity of the largest unit within an interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requiring detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators, combined with the loss of load criterion, are proposed to identify the potential reliability risk associated with failure of a SPS. Subsequent sections of this report recommend requirements for assessment and design of SPS based on whether the potential reliability risk associated with the SPS are significant versus limited impacts.

The proposed thresholds differentiate between significant and limited impact. While it should be clear there is no upper threshold on what constitutes a significant impact, there also is no lower threshold proposed as to what constitutes limited impact. Whether a scheme is an SPS is determined by the definition; significant and limited impact are used only to classify SPS. For example, if a scheme is installed to meet system performance requirements identified in the NERC Reliability Standards then it is an SPS regardless of its potential impact. A failure of the SPS would result in a violation of a NERC Reliability Standard. Thus, excluding a scheme with impact below a certain threshold would undermine the reliability objective of the standard requirement the scheme is installed to address.

<sup>9</sup> I.e., Eastern, Western, ERCOT, or Quebec Interconnection.

# Chapter 2 – Design and Maintenance Requirements

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Under the proposed definition, SPS are implemented to preserve acceptable system performance, and as such may be critical to power system reliability and therefore subject to single component failure considerations, and maintenance and testing requirements outlined in the PRC standards.

## General Design Considerations

Aside from the single component failure, and maintenance and testing considerations outlined below, Disturbance Monitoring Equipment should be provided in the design of an SPS to permit analysis of the SPS performance following an event. Also, as with other automated systems, the design of an SPS should facilitate its maintenance and testing.

## SPS Single Component Failure Requirements

Requirement R1.3 in PRC-012-0 requires SPS owners to demonstrate an SPS is designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0. This requirement should be retained in future standards such that Types PS and PL SPS are required to be designed so that power system performance meets the performance requirements of TPL-001-0, TPL-002-0, or TPL-003-0, in the event of a single component failure. The design of Type PS and PL SPS can provide the required performance through any of the methods outlined below, or a combination of these methods:

1. Arming more load or generation than necessary to meet the intended results. Thus the failure of the scheme to drop a portion of load or generation would not be an issue. In this context it is necessary to arm the tripping of more load delivery points or generating units rather than simply arming more MW of load or generation. When this option is used, studies of the SPS design must demonstrate that tripping the total armed amount of load or generation will not cause other adverse impacts to reliability.
2. Providing redundancy of SPS components listed below.
  - Any single ac current source and/or related input to the SPS. Separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing should be considered an acceptable level of redundancy.
  - Any single ac voltage source and/or related input to the SPS. Separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device should be considered an acceptable level of redundancy.
  - Any single device used to measure electrical quantities used by the SPS.
  - Any single communication channel and/or any single piece of related communication equipment used by the SPS.
  - Any single computer or programmable logic device used to analyze information and provide SPS operational output.
  - Any single element of the dc control circuitry that is used for the SPS, including breaker closing circuits.
  - Any single auxiliary relay or auxiliary device used by the SPS.
  - Any single breaker trip coil for any breaker operated by the SPS.
  - Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

3. Using remote or time delayed actions such as breaker failure protection<sup>10</sup> or alternative automatic actions to back up failures of single components (e.g., an independent scheme that trips an element if an overload exists for longer than the time necessary for the SPS to take action). The backup operation would still need to provide mitigation to meet the necessary result in the required timeframe.
4. For Type PL SPS, manual backup operation may be used to address the failure of a single SPS component if studies are provided to show that implemented procedures will be effective in providing the required response when a SPS failure occurs. The implemented procedures will include alarm response and manual operation time requirements to provide the backup functions.

Some SPS utilize an Energy Management System (EMS) system for transmitting signals or calculating information necessary for SPS operation such as the amount of load or generation to trip. Loss of the EMS system must be considered when assessing the impact of a single component failure. For example, when the EMS is used to transmit a signal, a separate communication path must be available. When a non-redundant EMS provides a calculated value to two otherwise independent systems, a backup calculation or default value must be provided to the SPS in the event of an EMS failure.

Types ES and EL SPS are designed to provide system protection against extreme events. The events that Types ES and EL SPS are intended to address have a lower probability of occurrence and the TPL standards do not require mitigation for these events. Dependability of SPS operation is therefore not critical for these events and, consistent with the existing standards, these SPS should not be required to perform their protection functions even with a single component failure. Design requirements for Type ES SPS should emphasize security; however, in some cases Type ES SPS are installed to address an event with consequences so significant (e.g., system separation or collapse of an interconnection) that consideration should be given to both dependability and security. In consideration that the addition of redundancy in some cases might make the SPS less secure, such cases may warrant implementation of a voting scheme<sup>11</sup>.

## Maintenance and Testing

The Project 2007-17, Protection System Maintenance and Testing, drafting team revised PRC-005 to include maintenance and testing requirements for SPS contained in PRC-017-0.<sup>12</sup> All of the existing requirements in PRC-017-0 that are based on a reliability objective are mapped to PRC-005-2. However, this report identifies two subjects that are not covered in either the existing standard or the proposed standard:

- Complex SPS require different procedures than those used for maintenance of protection systems.
- Maintenance of non-protection system components used in SPS is not addressed in any existing NERC Reliability Standards.

These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

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<sup>10</sup> In this context it is not intended that breaker failure protection must be redundant; rather, that breaker failure protection may be relied on to meet the design requirements (e.g., if an SPS required tripping a breaker with a single trip coil).

<sup>11</sup> A voting scheme achieves both dependable and secure operation by requiring, for example, two out of three schemes to detect the condition prior to initiating action.

<sup>12</sup> PRC-005-2 was adopted by the NERC Board of Trustees on November 7, 2012

## Chapter 3 – Study and Documentation Requirements

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### Review and Approval of New or Modified SPS

Requirement R1 in PRC-012-0 requires each Regional Reliability Organization to have a documented review procedure to ensure that SPS comply with regional criteria and NERC Reliability Standards. However, the potential for SPS interaction and for SPS operation or misoperation to have inter-regional impacts suggests that a uniform procedure for reviewing SPS is important to ensure bulk power system reliability. This report recommends fundamental aspects that should be included in a continent-wide SPS review procedure and included in the revised reliability standards pertaining to SPS. The review process should be conducted by an entity or entities with the widest possible view of system reliability, and must be a user, owner, or operator of the bulk power system. To assure that both planning and operating views are evaluated before a new or modified SPS is placed in service, responsibility for reviewing and approving implementation of SPS should be assigned to the Reliability Coordinator and Planning Coordinator. Ideally these reviews should be performed on a regional or interconnection-wide basis. If in the future an entity is registered as the Reliability Assurer for each Region, the responsibility for performing these reviews, or alternately for coordinating these reviews, should be assigned to the Reliability Assurer.

A continent-wide review process should be established in a revised reliability standard that includes the following aspects:

- The SPS owner<sup>13</sup> should be required to obtain approval from its Reliability Coordinator and its Planning Coordinator in whose area the SPS is installed<sup>14</sup> prior to placing a new or modified SPS in service.
- An entity proposing a new or modified SPS should be required to file an application with its Reliability Coordinator and Planning Coordinator that includes the following information:
  - A document outlining the details of the SPS as specified below in the section titled, Data Submittals by Entities that Own SPS.
  - Studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. The study report should include the following:<sup>15</sup>
    - Entity conducting the SPS study
    - Study completion date
    - Study years
    - System conditions
    - Contingencies analyzed
    - Demonstration that the SPS meets criteria discussed in the Design Considerations chapter of this report
    - Discussion of coordination of the SPS with other SPS, UFLS, UVLS, and protection systems
- The Reliability Coordinator and Planning Coordinator should be required to provide copies of the application and supporting information to Transmission Planners, Transmission Operators, and Balancing Authorities within their area, and to adjacent Reliability Coordinators and Planning Coordinators.
- Entities receiving the application should be allowed to provide comments to the Reliability Coordinator and Planning Coordinator.

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<sup>13</sup> In cases where more than one entity owns an SPS, the standards should designate that a designated “reporting entity” be responsible for transmitting data to the Reliability Coordinator and Planning Coordinator, while all owners retain responsibility for other requirements such as maintenance and testing.

<sup>14</sup> In cases where an SPS has components installed in or takes action in more than one Reliability Coordinator area or Planning Coordinator area, all affected Reliability Coordinators and Planning Coordinators should have approval authority.

<sup>15</sup> The same documentation requirements should apply to Periodic Comprehensive Assessments of SPS Coordination.

- When deciding whether to approve an SPS, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is to be installed or modified should be required to consider supporting information provided with the application; comments from Transmission Planners, Transmission Operators, and Balancing Authorities and other Reliability Coordinators and Planning Coordinators; and any supplemental information provided by the SPS owner.
- The basis of the Reliability Coordinator and Planning Coordinator approval should be limited to whether all required information has been submitted and the studies are sufficient to support that all performance requirements are met.

## Assessment of Existing SPS

### Study of SPS in Annual Transmission Planning Assessments

Requirement R1 in PRC-014-0 specifically addresses assessment of the operation, coordination, and effectiveness of all SPS and assigns this responsibility to the Regional Reliability Organization. Reliability standards must assign responsibility to owners, operators, and users of the bulk power system. For assessments of SPS, it is important to identify an entity with the necessary expertise in system studies and a wide-area view to facilitate coordination of SPS across the system. Instead of assigning this responsibility to the Regional Reliability Organization or the Regional Entity, the assessment responsibility should be assigned to the Planning Coordinator and Transmission Planner for SPS within their specific area.

Annually, the Planning Coordinator and Transmission Planner should review the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. If system changes have occurred which can affect the operation of the SPS, annual studies should include system conditions and contingencies modeled in the study supporting the application for installation of or modifications to an SPS.

Any issues identified should be documented and submitted to the Reliability Coordinator and the SPS owner. The Reliability Coordinator and Planning Coordinator should be required to determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

### Periodic Comprehensive Assessments of SPS Coordination

Comprehensive assessment should occur every five years, or sooner, if significant changes are made to system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems. Responsibility for the comprehensive assessment should be assigned to the Reliability Coordinator to achieve the wide-area review necessary for a comprehensive assessment. Planning Coordinators, Transmission Planners, Transmission Operators, Balancing Authorities, and adjacent Reliability Coordinators should be required to provide support to the Reliability Coordinator when requested to do so. As part of the periodic review the Reliability Coordinator should be required to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets criteria discussed in the Design Considerations chapter of this report, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.

The Reliability Coordinator should be required to provide its periodic assessment to Planning Coordinators, Transmission Planners, Transmission Operators, and Balancing Authorities in its area, and to adjacent Reliability Coordinators, and should be required to consider comments provided by these entities. Any issues identified with an SPS should be documented and submitted to the SPS owner. If any concerns are identified, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is installed should determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

## Documentation Requirements

### Data Submittals by Entities that Own SPS

Reliability standard PRC-015-0 establishes requirements for SPS owners to provide data for existing and proposed SPS as specified in reliability standard PRC-013-0 Requirement R1. PRC-013-0 establishes the data provided shall include the following:

- Design Objectives — Contingencies and system conditions for which the SPS was designed
- Operation — The actions taken by the SPS in response to Disturbance conditions
- Modeling — Information on detection logic or relay settings that control operation of the SPS

This requirement should be carried forward to the revised standards for the SPS owner to provide detailed information regarding the conditions of SPS operation. However, this requirement should be modified to ensure that communication of this information is clear and understandable to all entities that require the information to plan and operate the bulk power system (e.g., Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities). Additional specificity should be added to this list of data to assure that sufficient information is provided for entities to understand and model SPS operation.

Since SPS design and complexity vary considerably, a brief description of the action taken when certain system conditions are detected generally does not provide a sufficient level of detail. Conversely, logic and control wiring diagrams may provide too much detail that is not readily understood except by the SPS owner's protection and control engineers. To achieve an appropriate level of detail that provides a common understanding by the SPS owner and other entities, the SPS owner should work with the Transmission Planner to develop a document outlining the details of the SPS operation specifically tailored to the needs and knowledge level of the entities that require this information to plan and operate the bulk power system. The document should include the following:

- SPS name
- SPS owner
- Expected in-service date
- Whether the SPS is intended to be permanent or temporary
- SPS classification (per revised definition), and documentation or explanation of how the SPS mitigates the planning or extreme event and why the impact is significant or limited
- Logic diagram, flow chart, or truth table documenting the scheme logic and illustrating how functional operation is accomplished
- Whether the SPS logic is:
  - Event-based<sup>16</sup>
  - Parameter-based<sup>17</sup>
  - A combination of event-based and parameter-based
- System performance criteria violation necessitating the SPS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

<sup>16</sup> Event-based schemes directly detect outages and/or fault events and initiate actions such as generator/load tripping to fully or partially mitigate the event impact. This open-loop type of control is commonly used for preventing system instabilities when necessary remedial actions need to be applied as quickly as possible.

<sup>17</sup> Parameter-based schemes measure variables for which a significant change confirms the occurrence of a critical event. This is also a form of open-loop control but with indirect event detection. The indirect method is mainly used to detect remote switching of breakers (e.g., at the opposite end of a line) and significant sudden changes which can cause instabilities, but may not be readily detected directly. To provide timely remedial action execution, the measured variables may include power, angles, etc., and/or their derivatives.

- Parameters and equipment status monitored as inputs to the SPS (e.g., voltage, current or power flow, breaker position) and specific monitoring points and locations
- Under what conditions the SPS is armed (e.g., always armed, armed for certain system conditions, actuation thresholds)
- Whether arming is accomplished automatically or manually, if required
- Arming criteria – analog quantities and/or equipment status monitored to determine existence of the system condition for which SPS is armed (e.g., generation/load patterns, reactive power reserves, facility loading)
- Action taken – for example: transmission facilities switched in or out; generators tripped, runback, or started; load dropped; tap setting changed (phase-shifting transformer); controller set-point changed (AVR, SVC, HVdc converter); turbine fast valving or generator excitation forcing; braking resistor insertion
- Time to operate, including intentional time delays (e.g., timer settings) and inherent delays (e.g., relay operating time)
- Information with sufficient detail necessary to model the SPS.

### SPS Database

PRC-013-0, Requirement R1 requires the Regional Reliability Organization to maintain an SPS database, including data on design objectives, operation, and modeling of each SPS. Similar to the other requirements presently assigned to the Regional Reliability Organization, this requirement should be assigned to a user, owner, or operator of the bulk power system. To minimize the number of databases and facilitate sharing of information with entities that require SPS data to plan and operate the bulk power system, this requirement should be assigned to the Planning Coordinator. The Planning Coordinator should be required to provide its database to NERC for the purpose maintaining a continent-wide data base<sup>18</sup> that NERC would make available to Reliability Coordinators, Transmission Operators, Balancing Authorities, Planning Coordinators, and Transmission Planners that require this data. The database should contain information for each SPS as described above in the section titled, Data Submittals by Entities that Own SPS.

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<sup>18</sup> The requirement in a NERC Reliability Standard would be applicable to the Planning Coordinator; the responsibility for NERC to maintain a continent-wide database should be addressed outside the standard.



## Chapter 4 – Operational Requirements

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Due to their unique nature, SPS may have special operational considerations, with potentially differing requirements among the proposed types for monitoring, notification of status, and the response time required to address SPS failure. Furthermore, consideration should be given to the documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.

One entity should be assigned primary responsibility for monitoring, coordination, and control of an SPS. Depending on the complexity, this responsible party may be a Reliability Coordinator, Balancing Authority, or Transmission Operator. Complex SPS may have multiple owners or affected entities, including different functional entities and the chain of notification and control should be clearly established.

### Monitoring of Status

Existing NERC Reliability Standard IRO-005-3.1a, Requirement R1.1 requires Reliability Coordinators to monitor SPS. Similarly PRC-001-1, Requirement R6 requires Balancing Authorities and Transmission Operators to monitor SPS. The SPS standards should establish the level of monitoring capability that must be provided by the SPS owner. Classification of the SPS will dictate its design criteria and may lend itself to different levels of monitoring.

All SPS should be monitored by SCADA/EMS with real-time status communicated to EMS that minimally includes whether the scheme is in-service or out-of-service, and the current operational state of the scheme. For SPS that are armed manually the arming status may be the same as whether the SPS is in-service or out-of-service. For SPS that are armed automatically these two states are independent because an SPS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met. In cases where the classification of the SPS requires redundancy, the minimal status indications should be provided for each system. The minimum status is sufficient for operational purposes; however, where possible it may be useful to provide additional information regarding partial failures or the status of critical components to allow the SPS owner to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the SPS. While all schemes should be required to provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring similar to what is provided for microprocessor-based protection systems.

Similarly, the SCADA/EMS presentation to the operator would need to indicate the criticality of the scheme (e.g., through the use of audible alarms and a high priority in the alarm queue). The operator would be expected to know how to respond depending on the nature of the issue detected, as some partial SPS failures might not result in a complete failure of the scheme.

In cases where SPS cross ownership and operational boundaries, it is important that all entities involved with the SPS are provided with an appropriate level of monitoring.

### Notification of Status

Since the owner and operator of an SPS or component are often different organizations, and because SPS may cross entity boundaries, it is important that the SPS status is communicated appropriately between entities. Existing NERC Reliability Standards already require some level of notification of SPS status by Reliability Coordinators, Balancing Authorities and Transmission Operators.<sup>19</sup> Furthermore, SPS owners (e.g., Transmission Owner, Generator Owner) should be responsible for communicating scheme or component issues to the operating organizations (e.g., Transmission Operator, Generator Operator), who should then be responsible for communicating the issues to the involved Reliability Coordinator, Balancing Authority, and other Transmission Operators or Generator Operators that might rely on the SPS (for example, in setting operating limits).

The required timing associated with such notification will depend on the type of scheme; for example, the misoperation of a Type PS or ES scheme would require rapid notification to all interested parties. In general, the more critical a scheme is to the reliability of the system, the then more important its notification and response; however, it is also important that some

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<sup>19</sup> See, for example, IRO-005-3.1a Requirement R9 and PRC-001-1, Requirement R6.

level notification be made for all schemes, due to the complex nature of SPS and their interaction with each other, to allow entities to understand the reliability impact of a neighboring entity's SPS failure or misoperation.

## Response to Failures

As with many of the other issues, the response time required to address SPS failure is tightly coupled to the potential impact of the SPS as well as the operating conditions at the time of failure. For example, if the SPS is intended to address an event with a significant impact such as an IROL, then any corrective action in response to a misoperation would need to be taken in 30 minutes or less, consistent with the  $T_v^{20}$  associated with the IROL. On the other hand, depending on the operating conditions, a particular scheme's unavailability may not result in an adverse impact to reliability. Actions taken following an SPS failure should consider whether the failure affects dependability or security of the SPS and the potential impact to reliability.

Generally speaking, the SPS failure modes are known and the necessary corrective actions are documented (e.g., contingency plans) so that the system can be placed in a safe operating state. In any case, a full or partial failure of an SPS requires that the system performance level provided by having the SPS in service is met, or a more conservative and safe operating condition would need to be achieved, in a timeframe appropriate for the nature of the SPS and operating conditions. When one system of a redundant SPS fails, the action taken by the operator may depend on the system conditions the SPS is installed to address and the operating conditions at the time of the failure. For example, an operator may respond to failure of one system by operating to higher equipment ratings when an SPS is installed to address thermal loading violations. However, the operator may not be able to rely on the remaining system of a redundant SPS when the SPS is installed to prevent instability, system separation, or cascading outages, in which case the operator must reduce transfers or take other actions to secure the system.

## Operational Documentation

Operational documentation is necessary to provide the operator with enough information to understand all aspects of the scheme and is used to provide knowledge transfer as staff changes occur. Overall documentation requirements are identified in the section on Study and Documentation Requirements; however, the operator does not require all information provided by the SPS owner for the database maintained by the Planning Coordinator. The operational documentation is sometimes called a "description of operations" and provides the operation actions for the following areas:

- General Description – This provides an overview of the purpose of the scheme including the monitoring, set points and actions of the scheme. The operator and other stake holders can use this information to understand the need for the scheme.
- Operation – This will provide the specific information concerning, arming, alarming, and actions taken by this scheme including the monitoring points of the scheme. The operator can use this information to provide triage and plan a course of action concerning restoration of the electric system. This information should provide an understanding of what has operated, why these elements have been impacted, and possible mitigations or restoration activities.
- Failures, Alarms, Targeting – This information will provide the operator and first responders with descriptions of alarms and targets and the actions needed when the scheme is rendered unusable either during maintenance or because of a failure. The instructions will guide the operator on how to respond to component failures that partially impair the scheme or those failures that might disable entire scheme.

Regulatory agencies provide oversight of these schemes and require owners of these schemes to provide descriptions and operational information. NERC PRC-015 requires owners to provide description of schemes and the Study and Documentation Requirements section of this report proposes specific documentation requirements for inclusion in a revised standard. In addition to NERC, some Regional Entities also require SPS owners to provide the Region with additional information concerning the operations of the schemes. Some regional regulatory agencies also require the owners to verify that they have taken certain actions after a misoperation or a failure of these schemes.

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<sup>20</sup> Specifically,  $T_v$  is discussed in NERC Reliability Standard IRO-009-1, Requirement R2.

## Chapter 5 – Analysis of SPS Operations

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Operations of SPS provide an opportunity to assess their performance in actual operating power systems, as opposed to assessing the impact through a preconceived set of system studies. Analysis of SPS operations is presently addressed in PRC-012-0 and PRC-016-0.1, which establish requirements for Regional Reliability Organizations and SPS owners respectively. PRC-012-0 requires that each Regional Reliability Organization establish a regional definition of an SPS misoperation (R1.6), as well as requirements for analysis and documentation of corrective action plans for all SPS misoperations (R1.7). PRC-016-0.1 requires that SPS owners analyze their SPS operations and maintain a record of all misoperations in accordance with their regional SPS review procedure (R1) and that SPS owners take corrective actions to avoid future misoperations (R2).

PRC-012-0 is one of the standards identified in FERC Order No. 693 as a fill-in-the-blank standard and this standard therefore is not mandatory and enforceable. SAMS and SPCS have not identified any rationale for having regional definitions of an SPS misoperation or regional processes for analyzing SPS operations. Establishment of a continent-wide definition and review process will facilitate meaningful metrics for assessing the impact of SPS misoperations on bulk power system reliability. Rather than revising PRC-012-0 to assign responsibility for developing regional definitions and review processes to a user, owner, or operator of the bulk power system, this report recommends that one continent-wide definition and review process should be established through the NERC Reliability Standard Development Process, and that criteria be established for SPS owners to follow a continent-wide review process in place of the existing requirements in PRC-016-0.1.

### SPS Misoperation Definition

Establishing a definition of an SPS misoperation must account for the many different aspects affecting whether operation of an SPS achieves its desired effect on power system performance. In addition to aspects traditionally considered in assessing protection system misoperations such as failure to operate and unnecessary operation, analysis of an SPS operation also must consider whether the action was properly initiated and whether the initiated action achieved the desired power system performance. This report proposes that a tiered definition be used to assess which aspects of an SPS operation are reportable for metric purposes, which require analysis and reporting to the Reliability Coordinator and Planning Coordinator, and which require a corrective action plan. The following definition is recommended for an SPS misoperation.

#### *SPS Misoperation*

A SPS Misoperation includes any operation that exhibits one or more of the following attributes:

- a. Failure to Operate – Any failure of a SPS to perform its intended function within the designed time when system conditions intended to trigger the SPS occur.
- b. Unnecessary Operation – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s).
- c. Unintended System Response – Any unintended adverse system response to the SPS operation.
- d. Failure to Mitigate – Any failure of the SPS to mitigate the power system conditions for which it is intended.

The SPS review process should include requirements based on the SPS misoperation definition as follows:

- The SPS owner must provide analysis of all misoperations to its Reliability Coordinator and Planning Coordinator.
- The SPS owner must develop and implement a corrective action plan for all SPS misoperations.
- Reporting for reliability metric purposes should be limited to SPS misoperations that exhibit attributes (a) or (b) of the proposed definition, but should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

## SPS Operation Review Process

The review process should be included in a revised version of PRC-016 and PRC-012-0 should be retired upon approval of a continent-wide definition and revised PRC-016. The SPS operation review process should require that SPS owners analyze all SPS operations in sufficient detail to determine whether or not the response of the power system to the SPS operation is appropriate to meeting the purpose of the SPS. This requirement should be applied uniformly to all SPS types. The time required to review each SPS operation will vary with the complexity of the SPS.

The analysis of each operation should include:

- The power system conditions which triggered the SPS.
- A determination of whether or not the SPS responded as designed.
- An analysis of the power system response to the SPS operation.
- An analysis of the effectiveness of the SPS in mitigating power system issues it was designed to address. This analysis should identify whether or not those issues existed or were likely to occur at the time of the SPS operation.
- Any unintended or adverse power system response to the SPS operation.

For each SPS operation, the analysis should identify the power system conditions which existed at the time of the SPS operation. These conditions should be analyzed to determine whether or not the SPS operation was appropriate. This part of the analysis is to determine both whether or not the SPS operated as designed, and whether or not the conditions the SPS is intended to mitigate were present at the time of SPS operation.

Some SPS use a proxy to determine the possible existence of a system problem. For example, the opening of a generator outlet may cause an overload remote from the generator. An SPS could monitor the status of the outlet and run back generation to avoid the possible overload, rather than monitoring the loading on the potentially impacted element. The analysis should determine whether the SPS responded to the loss of outlet, and whether the overload actually would have occurred without SPS operation.

The analysis should also examine the response of the system to the SPS operation. This part of the analysis is to determine whether or not the SPS is effective in its intended mitigation, and if it has unforeseen adverse or unnecessary impacts on the power system.

As noted with the proposed definition above, the reporting requirements for each SPS misoperation should vary based on the attributes of the misoperation. The following discussion proposes reporting requirements and provides rationale for the type of SPS misoperation to which each should apply.

1. The SPS owner should be required to provide analysis of the misoperation to its Reliability Coordinator and Planning Coordinator for all SPS misoperations. The report should be provided to the Reliability Coordinator and the Planning Coordinator because such misoperations may require a reevaluation of the SPS under the review process proposed in the Study and Documentation Requirements section. The report should include the corrective action to assist the Reliability Coordinator and Planning Coordinator in confirming whether the SPS requires reevaluation.
2. The SPS owner should be required to develop and implement a corrective action plan for all SPS misoperations. Reporting details of the corrective action plan should be limited to purposes supporting reliability. As noted above, the report to the Reliability Coordinator and Planning Coordinator should include corrective actions. If an SPS must be removed from service or its operation is modified pending implementation of the corrective action plan, the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.
3. The SPS owner should be required to report for reliability metric purposes any SPS misoperation that involves a failure to operate or unnecessary operation. These attributes are analogous to protection system misoperations that must be reported and involve a failure of the SPS to operate per its installed design. The mechanism for

requiring reporting for reliability metric purposes should be similar to the process for reporting protection system misoperations under development in Project 2010-05.1: Protection Systems: Phase 1 (Misoperations).

4. The SPS owner should not be required to report or develop corrective action plans for other failures associated with an SPS that are not associated with an SPS operation or failure to operate, such as:
  - Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed;
  - Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and
  - Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions, if the system design requires automatic reset.

These types of failures can be corrected by the SPS owner without involving the Reliability Coordinator and the Planning Coordinator, and are analogous to a protection system owner identifying a failed power supply on a relay. If the failure has not resulted in a misoperation then reporting and corrective action plans are not required. It should be noted however, that operational requirements apply and if an SPS must be removed from service the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

## Chapter 6 – Recommendations

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### Definition

The existing SPS definition in the NERC glossary lacks clarity and specificity necessary for consistent identification and classification of SPS. The following strawman definition is proposed.

#### *Special Protection System*

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

- a) Underfrequency or undervoltage load shedding
- b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature
- c) Autoreclosing schemes
- d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers
- e) Schemes that prevent high line voltage by automatically switching the affected line
- f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open
- g) Out-of-step relaying
- h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty
- j) Automatic sequences that proceed when manually initiated solely by an operator
- k) Sub-synchronous resonance (SSR) protection schemes
- l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

## Classification

SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed:

- Type PS: planning – significant,
- Type PL: planning – limited,
- Type ES: extreme – significant, and
- Type EL: extreme – limited.

The planning classification applies to schemes designed to meet system performance requirements identified in the NERC Reliability Standards, while the extreme classification applies to schemes designed to limit the impact of two or more elements removed, an extreme event, or Cascading.

The significant classification applies to a scheme for which a failure to operate or inadvertent operation of the scheme can result in non-consequential load loss greater than or equal to 300 MW, aggregate resource loss (tripping or runback of generation or HVdc) greater than the largest Real Power resource within the interconnection, loss of synchronism between two portions of the system, or negatively damped oscillations. The limited classification applies to a scheme for which a failure to operate or inadvertent operation would not result in a significant impact.

## Applicability to Functional Model Entities

Three of the existing SPS-related reliability standards (PRC-012-0, PRC-013-0, and PRC-014-0) assign requirements to the Regional Reliability Organization. These standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693. This report recommends that requirements be reassigned to users, owners, and operators of the bulk power system in accordance with the NERC Functional Model. The following recommendations are included in the report:

- Review of new or modified SPS – assign to Reliability Coordinators and Planning Coordinators.
- SPS database maintenance – assign to Planning Coordinators; have Planning Coordinators submit databases to NERC for maintenance of a continent-wide database.
- Assessment of existing SPS – assign Planning Coordinators and Transmission Planners responsibility to include SPS assessments in annual transmission planning assessments; assign Reliability Coordinators responsibility to coordinate a periodic assessment of SPS design and coordination.

## Revisions to Reliability Standards

Figure 1 provides a high-level overview of recommendations related to the six PRC standards that apply to SPS. Recommendations include consolidating the six existing standards into three standards.

- Combine all requirements pertaining to review, assessment, and documentation of SPS (presently in PRC-012-0, PRC-013-0, PRC-014-0, and PRC-015-0) in one new standard, PRC-012-1. The requirement in PRC-012-0 for regional procedures for reviewing SPS misoperations is superseded by recommendations for revisions to PRC-016-0.1. The requirement in PRC-012-0 for regional maintenance and testing requirements is superseded by PRC-005-2.
- Requirements pertaining to analysis and reporting of SPS misoperations should be revised in a new standard, PRC-016-1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004.
- Requirements pertaining to maintenance and testing of SPS already have been translated to PRC-005-2 by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Additional detail is provided in Table 2 in Appendix C – Mapping of Requirements from Existing Standards. This table summarizes the recommendations for how each requirement in the existing six SPS-related standards should be mapped to revised standards. The more significant recommendations are summarized below.

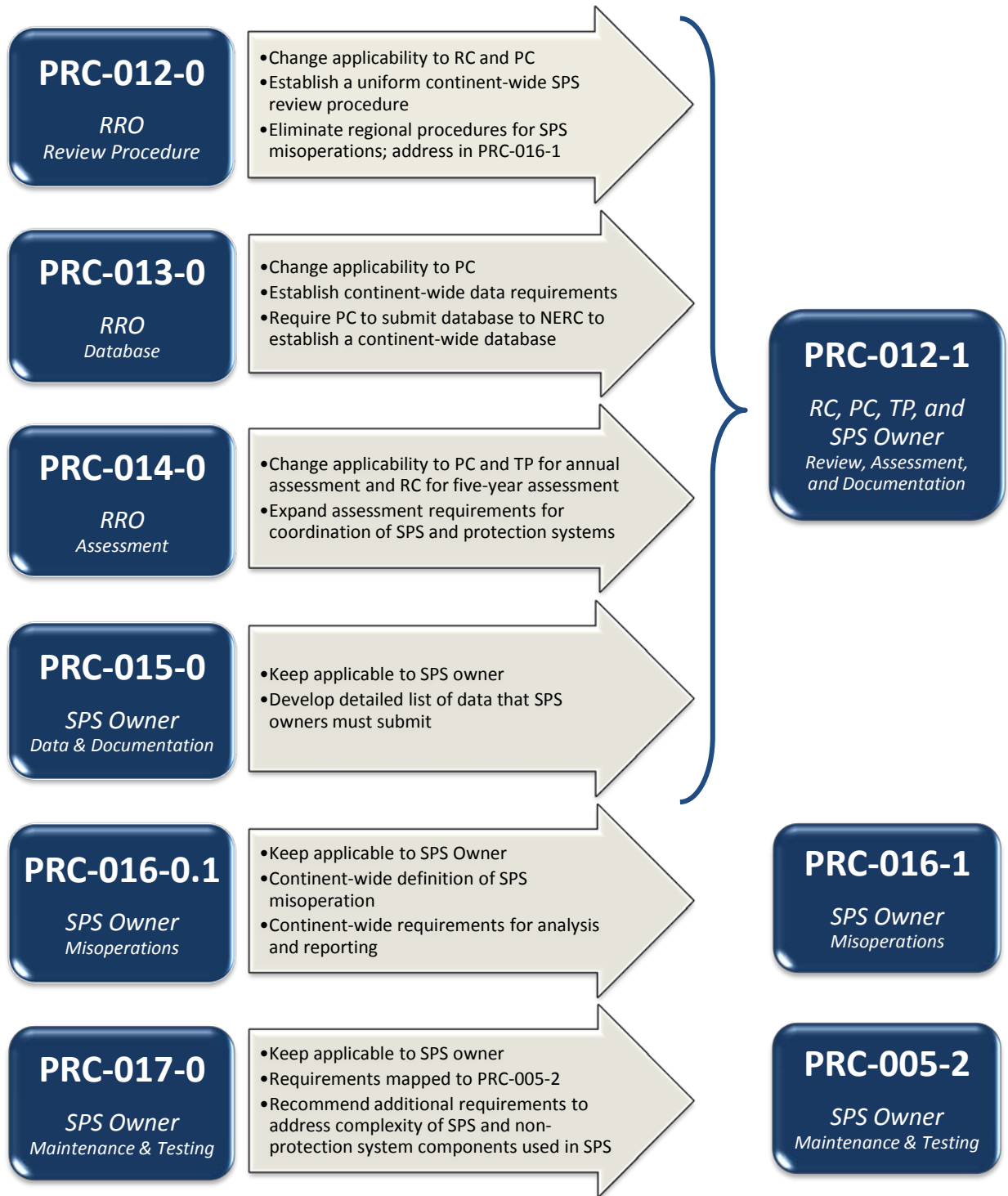


Figure 1 – Recommended Mapping of Existing PRC Standards



### **Standard PRC-012-1 – SPS Review, Assessment, and Documentation**

- SPS owners should be required to design Type PL and Type PS SPS so that a single SPS component failure does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, or TPL-003-0.
- Existing requirements for regional procedures for reviewing new or modified SPS should be replaced with a continent-wide procedure assigned to Reliability Coordinators and Planning Coordinators to assure a wide-area view of both planning and operational aspects of SPS.
- Annual transmission planning assessments should include an assessment by the Planning Coordinator and Transmission Planner to review the operation, coordination, and effectiveness of SPS, including the effect of correct operation, a failure to operate, and inadvertent operations.
- Periodic comprehensive assessments (every five years or less) of SPS should be performed by the Reliability Coordinator, with support as requested from other entities, to assess whether SPS are still necessary, serves their intended purpose, meet relevant design criteria, coordinate with other SPS, UFLS, UVLS, and protection systems, and do not have unintended adverse consequences on reliability.
- Detailed continent-wide requirements for data submittals should be established for SPS owners proposing new or modified SPS. Detailed recommendations are included in this report.
- Planning Coordinators should be assigned responsibility for maintaining databases containing all information submitted by SPS owners. Planning Coordinators should be required to submit their databases to NERC so that NERC can maintain and make available a continent-wide SPS database.

### **Standard PRC-016-1 – SPS Misoperations**

- PRC-016-1 should include a continent-wide definition of SPS misoperation based on the strawman definition proposed in this report.
- PRC-016-1 should include a continent-wide process for analysis of SPS operations and reporting SPS misoperations, including requirements for SPS owners to develop corrective action plans and provide analysis of SPS misoperations to Reliability Coordinators and Planning Coordinators.
- Reporting SPS operation and misoperation data for reliability metric purposes should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

### **Standard PRC-005-2 – Protection System Maintenance and Testing**

- Maintenance and testing requirements for SPS should be expanded in the NERC Reliability Standards to address the complexity of testing SPS and the maintenance of non-protection system components used in SPS. These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

### **Recommendations to Be Included in Other Standards**

This report discusses some aspects of SPS that are not addressed in the six SPS-related PRC standards. Recommendations should be incorporated in appropriate NERC Reliability Standards.

- SPS owners should be required to provide disturbance monitoring equipment to permit analysis of SPS performance following an event.
- Operating entities should be required to provide operators with documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.
- All SPS should be monitored by SCADA/EMS with real-time status communicated that minimally includes whether the scheme is in-service, out-of-service, and the current operational state of the scheme.
- One entity should be assigned responsibility for monitoring, coordination, and control of an SPS.

## Appendix A – Modeling and Simulation Considerations

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The addition of two stable control systems does not necessarily result in a stable composite control system; the same is true for SPS. Although the SPS may not be directly linked in their actions, their composite actions and effect on the electric system for commonly-sensed system conditions or perturbations can often behave as a single control system. Therefore, it is imperative that they be evaluated for their potential to interact with each other, particularly during a system disturbance. The composite interaction of multiple SPS, or of SPS with UFLS, UVLS, or other protection systems could result in system instability or cascading.

Because of the complexity of some schemes, modeling them in system simulation is currently performed most often by monitoring their trigger conditions and manually mimicking their intended actions such as changing system configuration, switching reactive devices, and adjusting or tripping generation. Such manual manipulations in powerflow and dynamics studies are only effective when studying a single SPS unless an iterative process is used. Even then, manual manipulation may not be effective and may not be possible in studying the simultaneous actions of multiple SPS that could potentially interact with each other. The difficulty is most significant when considering the potential interaction of parameter-based SPS, since interaction with event-based SPS would occur only if the initial event and SPS operation caused a second event to occur.

It is sometimes possible to simulate the behavior of a single SPS through simulation tools such as user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages. However, doing so for the myriad of SPS that may exist, even in a portion of an interconnection, is cumbersome. Furthermore, simulating multiple SPS in real-time operations tools (e.g., EMS) for real-time contingency analysis is extremely difficult and often requires new and innovative algorithm and software development. In addition, models used in real-time systems are often abridged or reduced equivalents and may not permit accurate representation of a particular SPS's functions. All of these issues are extremely problematic given the sheer number of SPS in North American interconnections.

To assure SPS will function in a coordinated fashion may require that they be modeled and studied from their design inception in the planning horizon, through pre-seasonal system studies that determine transfer capabilities, and in the operating horizon from day-ahead planning through the real-time contingency analysis that system operators depend on for guidance. Present analysis methods are limited by the capability of the software tools and management of the SPS, and in some cases protection system, data. The industry should put emphasis on future developments in these areas.

### General Considerations for Simulations

This section puts forth a number of factors, limitations, objectives, and overall guiding principles that a standard drafting team should consider in development of a new SPS standard with respect to the requirements for modeling and simulation, including data and process requirements necessary to support accurate and meaningful studies of SPS by Transmission Planners.

This report assumes that the modeling and simulation activities to be addressed are those performed for the planning horizon by Transmission Planning personnel. It is assumed that studies are performed using commercial off-the-shelf software packages and using databases derived from the interconnection-wide series of powerflow and dynamics cases. Studies using EMS based tools (e.g., study tools built into state estimators, real-time contingency analysis software, etc.) for real-time operations are not within the scope of this appendix.

It is important however, that the Transmission Planner share the results of planning horizon studies with operations personnel such that the impacts of SPS are effectively understood for the operating horizon also. This can be accomplished in a number of ways. Where operations support staff have similar study tools, sharing of the powerflow/dynamics cases, models, simulation scripts and similar data would enable them to evaluate SPS operation (or misoperation) for the operating horizon. Providing alarm or action limits for observable parameters (i.e., those that could be monitored in the operating environment) related to SPS operation would be another possibility. In this case, the parameters may be a direct indication or a proxy value that is indicative of the system condition of concern. Regardless of the process employed, the overriding consideration is that study results are adequately translated into actionable intelligence that is available to and understood by the system operator. While this is not intended to create a recommendation for a specific SPS standard

requirement, how this would ultimately be accomplished should be kept in mind as SPS standards are developed and implemented.

As a general rule, SPS are conceived by transmission planning engineers and implemented by protection and control engineers. To some extent, the engineers in these two groups are concerned with different aspects of SPS operation and use different terminology to describe SPS (and other system) functions. For example, a transmission planner may consider a protection system component failure to be a contingency while a protection engineer may consider this to be a design consideration. Transmission planning engineers conceive an SPS as a solution to system-level problems. Their focus is on the “big picture” functional operation of the SPS for specific system level conditions. Protection and control engineers implement an SPS via detailed design using various sensors, relays, etc. Their focus is on efficiently implementing the functional requirements as they understand them to be. It is imperative that the planning engineers effectively communicate the requirements of the SPS to protection engineers and monitor the design and implementation of the scheme to ensure that the SPS is implemented and functions as prescribed by the planner.

The planning and protection engineers should also consult with the operations personnel to ensure that possible system-level events which might result in unintended SPS operation are considered. Involving operations personnel at each stage of the design process will help ensure that the range of operating conditions likely to be encountered in the real world (including outages), as well as practical operating considerations, are also adequately considered in the SPS design and implementation.

An explicit requirement should exist to represent the salient features of SPS operation in a form that can be readily shared with, understood by, and used in simulations by other Transmission Planners. Simulation of SPS in powerflow or dynamic studies may involve a combination of using standard relay models, various monitoring features, and scripts or program code to adequately simulate the functioning of the SPS. These may include user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages (either executed during solution-run time or as user-written dynamic models), etc. Transmission Planners generally have their own individual preferences as to how to reflect these functions when performing simulations. Additionally, different Transmission Planning organizations have different levels of expertise in developing scenarios to reflect actual system operation and performing simulations based on those scenarios. Therefore, it is important that the modeling information to be used by other Transmission Planning engineers as input (including run scripts) in simulations be simple, understandable and well documented. Any scripts or models provided need to be “open source” in nature and well-documented to enable independent verification. The use of user models, FORTRAN object code, compiled scripts, and similar which make it difficult for the receiving Transmission Planner to review and understand how the SPS model functions must be avoided.

In addition to providing the relay models, program code/script, and similar input as part of the database, a summary document should be provided explaining the SPS. The information shared must include a summary and guidance document which includes the following, as applicable.

- An overview explanation of the basic functioning of the SPS, describing when and how it operates
- A listing of the setpoints applicable to the SPS (e.g., relay trip settings, etc.)
- A summary overview of how the SPS is being simulated via relay models, simulation scripts that may be provided
- Specific bus numbers, branch identifiers, machine identifiers, etc. should be referenced to help the Transmission Planner receiving this information understand how the SPS is being simulated

SPS modeling information should be readily available as part of the interconnection-wide modeling processes, but not an integral part of an interconnection-wide case year database. Specific recommendations are included in the chapter on study and documentation requirements.

Because of the special nature of SPS, it is not practical or even possible to include them in the interconnection-wide load flow and/or dynamic database case years in the classic sense (e.g., such as one would include a generator or FACTS device model). Additionally, it is simply not necessary to model all SPS for all simulations. The reality is that an SPS in the Northeast will likely have very little impact on the results of simulations focused on the Southeast. Therefore, including all SPS in all simulations places an unreasonable burden on Transmission Planners. However, due consideration should be given to the

interaction of a given SPS with other SPS. Note that geographical distance alone may not be sufficient justification not to consider the interaction of several SPS.

However, it is important that information about all SPS be available for use, as deemed appropriate by the Transmission Planners whose systems may be affected by the SPS operation (or misoperation). It is also important the relevant parameter-based SPS be modeled concurrently in simulations to appropriately evaluate potential interactions among the SPS.

Therefore, the data management process for providing SPS information for simulations purposes should include the following considerations.

- Sufficiently detailed SPS information and documentation as described above can be managed as part of the interconnection-wide powerflow and dynamic case creation process.
- Providing the models and simulation scripts alone is not sufficient. A functional description to assist the Transmission Planner in understanding how these modeling/simulation elements work to emulate the SPS function is necessary in order for the Transmission Planner to properly simulate and interpret the results of simulations involving the SPS.
- The SPS information may reside separately from the interconnection-wide powerflow and dynamic cases, but a clear association to each case must be evident.
- Each Transmission Planner will be able to select the SPS that are relevant to the simulation they are performing. Engineering judgment, with a documented reason, for excluding SPS from simulations is acceptable.
- Where included, the impact of multiple SPS and their interaction should be reasonably accounted for in the simulation activities.

It is envisioned that Transmission Planners will generally include only those SPS that, in their judgment, are relative to the simulations being performed and/or could potentially interact with other SPS being included in these simulations. However, it would be prudent to have some big picture check for unintended SPS interaction. Therefore, a joint, interconnection-wide study or assessment should be periodically performed to evaluate potential interactions among SPS across the entire interconnection. Such a study or assessment should include modeling and simulation of all of the SPS throughout the interconnection. A periodicity of five years for this joint study is suggested as an appropriate time frame.

## Use of SPS Simulations in Transmission Planning Studies

SPS are used as alternatives to transmission infrastructure to support reliable system operation for identified concerns. As such, these schemes must be analyzed in transmission planning analyses just as any other transmission system addition would be, with a focus on:

- Operation as expected for the design case of concern
- Understanding the potential for operation beyond the original design intent
- Determining if there is a potential for failure to operate to rectify the design case of concern.

In system planning, the types of studies which are typically performed to determine system performance are powerflow and dynamic simulations and analyses. SPS need to be modeled in both of these types of studies.

Powerflow (i.e., steady-state) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS monitoring and consequent actions with scripting and programming automatically called during powerflow processing
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- Contingencies are included in the analysis with and without the SPS actuated
- Monitoring of system performance to determine if system conditions would actuate an SPS

- The monitoring occurs for all contingencies examined
- Any result indicating potential actuation of an SPS is rerun with the SPS actuated

Dynamic (i.e., stability) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS in the dynamic simulation with a model that includes the monitoring and consequent actions during the dynamic simulations
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- The dynamic/stability contingencies are included in the analysis with and without the SPS actuated
- Monitoring of SPS trigger elements (voltage, current, flow and/or frequency on system elements or element status) to determine if actuation of an SPS would have actuated
  - Rerun the simulation with the SPS actuated if the monitored results indicate potential actuation of the SPS

The SPS modeling techniques used in system planning should be based upon modeling information provided by the SPS owner which clearly describes what the SPS senses and the consequent actions taken when its triggering needs are met.

The need for accurate modeling information can be demonstrated with an example. In the example, two SPS exist in an area. One SPS trips a large generating plant for loss of a transmission circuit due to first swing stability concerns. This SPS acts within cycles of the initiating line loss. The second SPS inserts a series reactor into a transmission circuit to limit flow and eliminate an overload on the circuit. The second SPS acts within seconds (5 seconds for this example) of the overload condition occurring.

Steady state studies of the area where these SPS exist would examine the representative cases (sets of system conditions) and contingency sets for the study in question. If the power flow software allowed, a post-solution program could be run to test if the actuating circumstances for each SPS were met; if so, the contingent solution would be rerun and tested again for any other SPS which would actuate. If the power flow software did not have this flexibility, the engineer could include an SPS actuation for those contingencies expected to trigger the SPS and run that expanded contingency list; the results could be examined with attention paid to the loading for the circuit protected by the second SPS. Any contingencies which caused an overload on the triggering circuit could be rerun with the SPS actuated.

Since both SPS act within the dynamic simulation timeframe, the SPS should be modeled or monitored in stability simulations. Dynamic models could exist for both SPS. Should the flow on the SPS-triggering line exceed the flow actuation setpoint for the required time duration, the dynamic simulation would capture the impact of the reactor insertion and the SPS actuation. If the SPS were not explicitly modeled, their trigger values could be monitored (i.e., the status or flow on the line for the first SPS and the flow on the potentially overloaded circuit for the second SPS). The monitored data channels would be examined after each simulation to determine if the simulation needed to be rerun while modeling the appropriate SPS actions.

The goal for modeling SPS in studies is to confirm that they will operate to correct the intended system concerns as necessary to preserve acceptable system performance. In addition, the analyses provide understanding for system planning and operations on when and how the use of the SPS may change over time. This information may be critical for system operations staff to maintain reliable system operation.

## Appendix B – Operational Considerations

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This information is a high level list of important issues and concerns if performing SPS analyses in real-time operations.

### Real-time SPS Evaluation

Current system conditions must be identified before evaluating whether an SPS would perform its function and achieve its desired outcome. Results of security analysis should be required to indicate whether an SPS should be armed (if armed manually) and whether an SPS will operate for a given contingency. Security analysis should model operation of the SPS in addition to the initiating contingency when the SPS is armed.

SPS evaluation often cannot be done with SCADA input alone. Some non-SCADA input may be needed; for example, limits from off-line studies are converted into inputs available in the Energy Management System (EMS). The inputs that support SPS evaluation and operation need to be codified in operating guides and presented on operator displays for ease of use and operation. Custom code and displays are generally required to aggregate all needed information for usage by engineers and operators in real time.

The impact of SPS operation on facilities external to the SPS owner/operator needs to be jointly considered and communicated to external entities and appropriately accounted for in EMS. Furthermore, the effects of external contingencies on the SPS triggers should be accounted for within EMS and known to operators.

SPS evaluation typically involves the testing of a limited set of relevant contingencies, requiring the use Real-Time Contingency Analysis (RTCA). In some cases, a dc solution to identify thermal issues is adequate; in other cases, a full ac solution is required (e.g., where triggers are voltage dependent).

Some EMS are not robust enough to compute ac solutions in EMS/RTCA. Depending on the classification of an SPS (e.g., significant), an EMS/RTCA with such limited capability would be insufficient to evaluate the impact of the SPS. In such cases it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

If the EMS/RTCA does not reach a solved state, then the SPS cannot be evaluated. For example, some EMS/RTCA will fail to solve or fail to converge upon the creation of islands in the model. In these cases, SPS modeling may require custom software solutions.

### Multiple Decision-Making Capability

When evaluating SPS in EMS/RTCA, intermediate steps must be modeled and intermediate states must be evaluated. It should be assumed that an SPS may suffer a full or partial failure and that system conditions will change as the SPS operates. Adverse conditions may arise during intermediate steps that lead to undesired outcomes or put the system into an unplanned operating state.

The post-contingency, pre-SPS-operation state must be known to assess system conditions before the SPS action can be evaluated. For example, the loss of a large nuclear station automatically activates a large emergency core cooling load. This new system state would require a re-solution to check post-contingent node voltage (i.e., with the load connected) before consideration of SPS activation and results can occur. This requires that several stages and intermediate actions be modeled in the evolution of the final system topology to ensure that the system can reach the desired end-state.

### Information Management

Each SPS may have its own set of arming and activation triggers. Examples include equipment status, line loading and voltage. These triggers may be complex, and could affect the alarming capability required of EMS.

Changes to EMS models may require long lead times before an SPS can be implemented; for example, changes to models often require pushing through multiple staged software environments. Entities should use software designs that are flexible to accommodate timely changes to SPS models that might not be tied to the network model database release schedule. When implementing an SPS before the EMS model can be updated, it is necessary to establish other means, such as

supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

## **Modeling Simplicity and Usability**

Complex SPS schemes require due diligence to maintain and support. Entities should be required to develop and document an efficient approach to SPS control. An entity's strategy should allow for concurrent and/or consecutive SPS actions.

## Appendix C – Mapping of Requirements from Existing Standards

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal   | Comments   |
|-------------------|---|--|--|
| PRC-012-0         | R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: | PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.   | See Review and Approval of New or Modified SPS on pp. 16-17. |
| PRC-012-0         | R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.  | PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.   | See Review and Approval of New or Modified SPS on pp. 16-17. |
| PRC-012-0         | R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.  | PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system. | See Data Submittals by Entities that Own SPS on pp. 18-19.   |
| PRC-012-0         | R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.  | PRC-012-1 should require that all Type PS and PL SPS are designed so system performance requirements are met in the event of a single component failure within the SPS.                                      | See SPS Single Component Failure Requirements on p. 14-15    |



**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal  | Comments   |
|-------------------|---|---|--|
| PRC-012-0         | R1.4. Requirements to demonstrate that the inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0. | PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation. | See Review and Approval of New or Modified SPS on p. 16.   |
| PRC-012-0         | R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.   | PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation. | See Review and Approval of New or Modified SPS on p. 16.   |
| PRC-012-0         | R1.6. Regional Reliability Organization definition of misoperation.   | A continent-wide definition of an SPS misoperation should be established.   | See SPS Misoperation Definition on p. 22.  |
| PRC-012-0         | R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.   | Do not carry forward to revised standards.  | The need for this requirement is eliminated by establishing continent-wide requirements in PRC-016-1. See SPS Operation Review Process on pp. 23-24.                         |
| PRC-012-0         | R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization’s review procedure and the process for Regional Reliability Organization approval of the procedure.                         | Do not carry forward to revised standards.  | The need for this requirement is eliminated by establishing a continent-wide review procedure within PRC-012-1. See Review and Approval of New or Modified SPS on pp. 16-17. |
| PRC-012-0         | R1.9. Determination, as appropriate, of maintenance and testing requirements.   | Do not carry forward to revised standards.  | The need for this requirement is eliminated by establishing continent-wide maintenance and testing requirements within PRC-005-2.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal  | Comments  |
|-------------------|---|---|---|
| PRC-012-0         | R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).                                       | Do not carry forward to revised standards.  | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-013-0         | R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information: | PRC-012-1 should require that each Planning Coordinator maintain a database, and provide the database to NERC for the purpose of maintaining a continent-wide database. | See SPS Database on p. 19.  |
| PRC-013-0         | R1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed,   | This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.     | See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.  |
| PRC-013-0         | R1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and   | This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.     | See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.  |
| PRC-013-0         | R1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS.  | This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.     | See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal   | Comments  |
|-------------------|---|--|---|
| PRC-013-0         | R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).  | Do not carry forward to revised standards.   | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-014-0         | R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.  | PRC-012-1 should require the Planning Coordinator and Transmission Planner to assess SPS in annual transmission planning assessments and require the Reliability Coordinator to conduct a periodic review every five years, or sooner if significant changes are made to the system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems. | See Periodic Comprehensive Assessments of SPS Coordination on p. 17.  |
| PRC-014-0         | R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days). | Do not carry forward to revised standards.   | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-014-0         | R3. The documentation of the Regional Reliability Organization’s SPS assessment shall include the following elements:   | PRC-012-1 should require the Reliability Coordinator to document its periodic assessments. The documentation should include the same elements required in a study supporting approval of a new or modified SPS.  | See Review and Approval of New or Modified SPS on pp. 16-17 and Assessment of Existing SPS on p. 17.  |
| PRC-014-0         | R3.1. Identification of group conducting the assessment and the date the assessment was performed.  | This list of elements includes: <ul style="list-style-type: none"> <li>Entity conducting the study</li> <li>Study completion date</li> </ul>   | See Review and Approval of New or Modified SPS on pp. 16-17.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal   | Comments   |
|-------------------|---|--|--|
| PRC-014-0         | R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed. | This list of elements includes: <ul style="list-style-type: none"> <li>• Study years</li> <li>• System conditions</li> <li>• Contingencies analyzed</li> <li>• Study completion date</li> </ul>  | See Review and Approval of New or Modified SPS on pp. 16-17.         |
| PRC-014-0         | R3.3. Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.  | PRC-012-1 should require the Planning Coordinator and Transmission Planner document and submit any issues identified in the annual assessment to the Reliability Coordinator.<br>PRC-012-1 should require the Reliability Coordinator to document and submit any issues identified in the periodic assessment to the SPS owner.  | See Assessment of Existing SPS on p. 17.                             |
| PRC-014-0         | R3.4. Discussion of any coordination problems found between a SPS and other protection and control systems.   | PRC-012-1 should require the Reliability Coordinator to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets performance criteria, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.  | See Periodic Comprehensive Assessments of SPS Coordination on p. 17. |
| PRC-014-0         | R3.5. Provide corrective action plans for non-compliant SPSs.   | PRC-012-1 should require that if issues are identified in an annual or periodic assessment, the Reliability Coordinator and Planning Coordinator determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in service until a corrective action plan is implemented.<br>If a corrective action plan is required, PRC-012-1 should require the SPS owner to submit an application for a new or modified SPS. | See Assessment of Existing SPS on p. 17.                             |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal  | Comments  |
|-------------------|---|---|---|
| PRC-015-0         | R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.   | PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.  | See Data Submittals by Entities that Own SPS on pp. 18-19.  |
| PRC-015-0         | R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.   | Do not carry forward to revised standards. PRC-012-1 should have a requirement for the SPS owner to file an application for approval of an SPS, which assures that the SPS is reviewed in accordance with the continent-wide review procedure prior to being placed in service. | See Review and Approval of New or Modified SPS on pp. 16-17.  |
| PRC-015-0         | R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days). | Do not carry forward to revised standards.  | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-016-0.1       | R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.  | PRC-016-1 should establish a continent-wide process for analyzing and reporting SPS misoperations.  | See SPS Operation Review Process on pp. 23-24.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard       | Requirement  | Proposal  | Comments  |
|-------------------------|--|---|---|
| PRC-016-0.1             | R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.   | PRC-016-1 should establish a requirement that the SPS owner should be required to develop and implement a corrective action plan for SPS misoperations. | See SPS Operation Review Process on pp. 23-24.  |
| PRC-016-0.1             | R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days). | Do not carry forward to revised standards.  | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-017-0 <sup>21</sup> | R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1.  |
| PRC-017-0               | R1.1. SPS identification shall include but is not limited to:  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Tables 1-1 – 1-5, and Table 2.   |
| PRC-017-0               | R1.1.1. Relays.  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-1.   |
| PRC-017-0               | R1.1.2. Instrument transformers.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-3.   |
| PRC-017-0               | R1.1.3. Communications systems, where appropriate.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-2.   |

<sup>21</sup> Mapping for requirements in PRC-017-0 are adapted from the mapping document developed by the Project 2007-17 Protection System Maintenance & Testing drafting team.

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement  | Proposal  | Comments  |
|-------------------|--|---|---|
| PRC-017-0         | R1.1.4. Batteries.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-4.   |
| PRC-017-0         | R1.2. Documentation of maintenance and testing intervals and their basis.  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1 and R2.   |
| PRC-017-0         | R1.3. Summary of testing procedure.  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1, Tables 1-1 – 1-5, and Table 2.   |
| PRC-017-0         | R1.4. Schedule for system testing.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1 and R2.   |
| PRC-017-0         | R1.5. Schedule for system maintenance.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1 and R2  |
| PRC-017-0         | R1.6. Date last tested/maintained.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R3 and associated Measures, R4 and associated Measure, and Data Retention.   |
| PRC-017-0         | R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days). | Addressed by Project 2007-17, Protection System Maintenance and Testing; this requirement is not carried forward to the revised standard. | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |

# Appendix D – Standards Committee Request for Research; January 9, 2011

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## Request for Research

Project 2010-05.2

Phase 2 of Protection Systems: SPS and RAS

### Introduction

NERC's Standards Committee has tentatively identified this project for initiation in late 2012. Prior to then, there is a need for additional research and scoping of the project to determine:

- What is the problem that this project will try to solve?
- Is the development of a standard the appropriate manner to solve that problem, or should alternative approaches be used?
- If a standard is appropriate, what is the recommended solution to the problem?

Results based standards projects use the approach of defining the needs, goals, and objectives for the project. For this project, we would like your assistance in this effort. Below is a draft problem statement for your consideration.

### *Need (Problem)*

**Special Protection Systems (SPS) and Remedial Action Schemes (RAS) can misoperate and negatively impact the reliability of the BES.**

Does the need above correctly document the concern described in the attached draft SAR?

Do you agree that this is a problem that needs to be addressed?

Is a standard the appropriate vehicle to address this problem, or should an alternative approach be used? If an alternative, is recommended, what would that alternative be?

If development of a standard is appropriate, then please consider the following Goal

### *Goal (Solution)*

**Require the analysis, reporting, and correction of Misoperations of SPS and RAS.**

### Request

Please provide the Standards Committee with the following information:

- An updated Need/Problem (or a statement of concurrence with the draft presented here)
- A statement indicating whether or not you believe this problem is one which needs to be addressed
- If you agree the problem needs to be addressed, a suggestion for how to address the problem
- If you suggest a standard be developed to address the problem, then please provide
  - An updated goal (or a statement of concurrence with the draft presented here)
  - A set of objectives in support of that goal
  - If you have any suggested changes to the attached draft SAR, please propose them
  - If you have specific recommendations for requirements language or additional information, please include them

Thank you in advance for your assistance.



## Appendix E – Scope of Work Approved by the Planning Committee; June 8, 2011

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### Assessment of Special Protection System Standards and Regional Practices

#### **Proposal:**

The SPCS proposes to conduct an assessment of the SPS-related PRC standards and definition of SPS, conduct an assessment of existing regional practices summarizing commonality and differences, and to document its findings in a report to the Planning Committee that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a Compliance Application Notice (CAN) to address part of this issue until a revised definition and standard(s) are developed. The SPCS further proposes this activity should be a joint effort with the Transmission Issues Subcommittee (TIS).

#### **Rationale:**

- The SPCS scope calls for providing subject matter expertise for NERC Standards related to protection systems and controls, and the SPCS work plan includes an assignment to review all existing PRC-series Reliability Standards, to advise the Planning Committee of its assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.
- The SPCS has reviewed all PRC standards except the group of SPS standards. The SPCS had started assessment of these standards, but the assessment was deferred due to other priority work such as the Power Plant and Transmission System Protection Coordination technical reference document.
- The SPCS has reviewed its work plan and determined that this is the next logical project for the SPCS. Work on the Transmission System Phase Backup Protection reliability guideline is wrapping up at this time and the SPCS can make the SPS review one of two priority activities for this year (the other is the document addressing operation of protection systems in response to power swings).
- The SPCS believes that a thorough review of SPS-related PRC standards would benefit from the expertise of TIS and the SPCS recommends a joint SPCS/TIS effort coordinated by the SPCS. This proposal has been reviewed with and is supported by TIS.
- The SPCS proposes to conduct an assessment of the standards and definition of SPS, and conduct an assessment of existing regional practices summarizing commonality and differences among the various regional practices.
- The SPCS believes that differences among regional practices must be resolved through a formal process; a consensus opinion of what constitutes an SPCS would lack standing unless it is vetted through a stakeholder process. The SPCS proposes to document its findings in a report that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a CAN to address part of this issue until a revised standard(s) is developed.
- The scope of work for such a review is significant and direction should come through the NERC Planning Committee as the body to which SPCS and TIS report.
- The SPCS believes that an appropriate time frame for completing this report would be to submit a draft to the Planning Committee at its March 2012 meeting. The SPCS and TIS believe this schedule is appropriate to support a thorough review.

Approved by the NERC Planning Committee  
June 8, 2011

# Appendix F – System Analysis and Modeling Subcommittee Roster

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## Appendix I – Revision History

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| Revision History |                |   |
|------------------|----------------|---|
| Version          | Date           | Modification(s)   |
| 0                | March 5, 2013  | Initial Document  |
| 0.1              | April 18, 2013 | Appendix A – Correction to remove trade names and replace with generic language in the section, General Considerations for Simulation |

**Exhibit H**

**Summary of Development History and Complete Record of Development**

## **Exhibit H: Summary of Development History**

The development record for the proposed definition of Remedial Action Scheme and the Proposed Reliability Standards is summarized below.

### **I. Overview of the Standard Drafting Team**

When evaluating a proposed Reliability Standard, the Commission is expected to give “due weight” to the technical expertise of the ERO<sup>1</sup>. The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit I.

### **II. Standard Development History**

#### **A. Technical Report**

On January 9, 2011, the NERC Standards Committee submitted a request for research to procure the information necessary to clearly define the deficiencies with the existing standards and definitions related to Special Protection Systems (“SPS”) and Remedial Action Schemes (“RAS”). Subsequently, a report written by the System Analysis and Modeling Subcommittee (“SAMS”) and System Protection and Control Subcommittee (“SPCS”) was approved by the Standards Committee on June 8, 2011 that addressed issues identified by the SAMS and SPCS as well as the Standards Committee request for research. That report included various recommendations for improvement of the existing definition of SPS and RAS as well as revisions to six SPS-related PRC standards.

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<sup>1</sup> Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

## **B. Standard Authorization Request (“SAR”) Development**

The SAR for Phase 2 of Project 2010-05.2 Phase 2 of Special Protection Systems was submitted on February 12, 2014 as a request for a revision to an existing standard. Phase 2 of Project 2010-5.2 was posted for a 30-day comment period from February 18, 2014 through March 19, 2014. The Standards Committee approved the SAR on June 10, 2014.

## **C. Informal Comment Period**

The Revised Definition of Special Protection System developed by the SPCS was posted for a 30-day informal comment period from March 11, 2014 and April 9, 2014. The standard drafting team considered all comments received in preparing the draft definition for formal comment.

## **D. First Posting-Comment Period**

The first drafts of the definition of Remedial Action Scheme and associated changes to various Reliability Standards were posted for a 45- public comment period from June 11, 2014 through July 25, 2014, with an initial ballot held from July 16, 2014 through July 25, 2014. Several documents were posted for guidance with the first drafts, including the Proposed RAS Definition, Implementation Plan, the SAR, *Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards*, *RAS Definition FAQ* and the PRC Project Coordination Plan. The initial ballot achieved 78.92% quorum, and an approval of 58.88%. There were 53 sets of responses, including comments from approximately 159 individuals from approximately 110 companies, representing all 10 industry segments.

The standard drafting team considered stakeholder comments regarding proposed revision to the Definition of Remedial Action Scheme and made the following modifications based on those comments:



- Changed the phrase “curtailing or tripping generation or other sources “ to “adjusting or tripping generation (MW and Mvar)”.
- Changed the phrase “curtailing or tripping load” to “tripping load”.
- Changed the introductory sentence to the objectives from: “RAS accomplish one or more of the following objectives” to “RAS accomplish objectives such as” because the objective list is no longer all inclusive.
- Inserted “Bulk Electric System” as a qualifier in the pertinent objectives.
- Removed the last objective: “Address other Bulk Electric System reliability concerns” because it was deemed overly broad
- Revised the fifth objective to read: “Limit the impact of Cascading or extreme event”
- Removed the sentence: “These schemes are not Protection Systems; however, they may share components with Protection Systems.”
- Added a new exclusion “a” that reads: “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements”.
- Combined exclusions “b” and “c” to read: “Schemes for automatic underfrequency load shedding and automatic undervoltage load shedding comprised of only distributed relays”.
- Changed exclusion “d” from “Autoreclosing schemes” to “Automatic Reclosing schemes” to be in alignment with Reliability Standard PRC-005-3.
- In exclusion “e”, changed the term “high voltage” to “overvoltage”.
- In exclusion “f”, removed the term “generation excitation”.
- In exclusion “k”, replaced “operator” with the defined term “System Operator”.
- Added a new exclusion “n” that reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing”.
- Updated implementation plan to add a specific Effective Date for PRC-024-1.
- Removed standards from the implementation plan that are currently in implementation phase.
- Removed retirement of “Special Protection System” from the implementation plan.
- The Background and FAQ document was updated to reflect the changes and additions made to the proposed definition.

#### **E. Second Posting - Comment Period and Additional Ballot**

The second draft of the proposed definition and associated Reliability Standard changes were posted for a 45- day public comment period from August 29, 2014 through October 14, 2014, with an additional ballot held from October 3, 2014 through October 14, 2014, with an additional ballot held from October 3, 2014 through October 14, 2014. The additional ballot achieved 80.54% quorum, and an approval of 75.79%. There were 46 sets of responses,

including comments from approximately 126 individuals from approximately 92 companies, representing 9 out of 10 industry segments.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard PRC-005-4 and made the following observations and modifications based on those comments:

- Lower-cased the word ‘reclosing’ in Exclusion ‘d’ because it is not a defined term in the Glossary of Terms Used in NERC Reliability Standards.
- Updated the list of Reliability Standards being revised to use the single defined term RAS with the new NERC numbering system.
- Removed PRC-024-1 and PRC-005-1 from the list of revised Reliability Standards to avoid any complications related to the timing of their associated implementations.
- The Background and FAQ document was updated to reflect the changes and additions made to the proposed definition.

#### **F. Final Ballot**

The final ballot of the proposed definition and associated Reliability Standard changes was conducted open from October 28, 2014 through November 6, 2014. The final ballot achieved quorum of 85.41% and an approval of 73.33%.

#### **G. Board of Trustees Adoption**

The proposed definition of Remedial Action Scheme and Proposed Reliability Standards were adopted by the NERC Board of Trustees on November 13, 2014.

**Program Areas & Departments Project 2010-05.2 Phase 2 of Special Protection Systems**  
 Project 2010-05.2 Phase 2 of Special Protection Systems  
 Rich HTML Content 1

Related Files

**Status:**

The **Revised Definition of Remedial Action Scheme** was adopted by the NERC Board of Trustees November 13, 2014 and is pending regulatory approval.

**Background:**

In early 2011, NERC staff decided to divide the approved project for Protection System Misoperations into two phases. Phase 1 of Project 2010-05 is addressing Misoperations of Protection Systems; the project began in April, 2011 and is ongoing. Project 2010-05.2 Special Protection Systems is Phase 2 of Protection Systems and will address all aspects of Special Protection Systems including misoperations of SPS. In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as “fill-in-the-blank” standards and did not approve or remand them because they are applicable to the Regional Reliability Organizations (RROs); consequently, they are not mandatory or enforceable. This project proposes to correct the applicability by assigning responsibilities to the specific users, owners, and operators of the Bulk-Power System. The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or Remedial Action Scheme (RAS), as used in the Western Interconnection, lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions. This leads to inconsistent application of the SPS-related Reliability Standards. At the request of the NERC Standards Committee, the Planning Committee directed the System Protection and Control Subcommittee (SPCS) to research this issue. The SPCS authored the attached report and provided a draft definition of SPS for consideration in the standards development process. This project proposes to establish a definition for SPS that provides the needed specificity to promote the consistent application of the NERC Reliability Standards related to SPS. This project also proposes to address, in part, four recommendations related to identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event. There is no FERC directive associated with the SPS project; however, this project is being coordinated with Project 2008-02 UVLS, which does have an associated directive in P 1509 of Order No. 693 to modify PRC-010-0. These projects are linked because the proposed definition for Special Protection Systems must be written relative to the proposed definition of UVLS Program.

| Draft  | Actions   | Dates   | Results  | Consideration of Comments |
|--|---|---|--|---------------------------|
| <p align="center"><b>Final Draft</b></p> <p align="center"><b>RAS Definition</b></p> <p>Clean (42)   Redline to Last Posted (43)</p> | <p align="center">Final Ballot</p> <p align="center">Info&gt;&gt; (49)</p> <p align="center">Vote&gt;&gt;</p> | <p align="center">10/28/14 -<br/>11/06/14</p> | <p align="center">Summary&gt;&gt; (50)</p> <p align="center">Ballot Results&gt;&gt;<br/>(51)</p> |                           |

|  |  |                                |  |   |
|--|--|--------------------------------|--|---|
| <p>Implementation Plan<br/>Clean (44)   Redline to Last Posted (45)</p> <p>Revised Reliability Standards for the Revised<br/>Definition of RAS (46)</p> <p><b>Supporting Documents:</b></p> <p>RAS Definition FAQ<br/>Clean (47)   Redline to Last Posted (48)</p>   |  |                                |  |   |
| <p><b>Draft 2</b><br/><b>Proposed RAS Definition</b><br/>Clean (27)   Redline to Last Posted (28)</p> <p>Implementation Plan<br/>Clean (29)   Redline to Last Posted (30)</p> <p>Revised Reliability Standards for the Revised<br/>Definition of RAS (31)</p>  | <p>Additional Ballot</p> <p>Updated Info&gt;&gt;<br/>(35)</p> <p>Info&gt;&gt; (36)</p> <p>Vote&gt;&gt;</p> <p>(Closed)</p>   | <p>10/03/14 -<br/>10/14/14</p> | <p>Summary&gt;&gt; (38)</p> <p>Ballot Results&gt;&gt;<br/>(39)</p> |   |
| <p><b>Supporting Documents:</b></p> <p>Unofficial Comment Form (Word) (32)</p> <p>RAS Definition FAQ (33)</p> <p>PRC Project Coordination Plan (34)</p>  | <p>Comment Period</p> <p>Info&gt;&gt; (37)</p> <p>Submit<br/>Comments&gt;&gt;</p> <p>(Closed)</p>  | <p>08/29/14 -<br/>10/14/14</p> | <p>Comments<br/>Received&gt;&gt; (40)</p>                          | <p>Consideration of<br/>Comments&gt;&gt; (41)</p> |
| <p><b>Draft 1</b><br/>Proposed RAS Definition (11)</p> <p>Implementation Plan (12)</p> <p>Revised Reliability Standards for the Revised<br/>Definition of RAS (13)</p> <p><b>Supporting Documents:</b></p> <p>Unofficial Comment Form (Word) (14)</p> <p>Standard Authorization Request<br/>Clean (15)   Redline to Last Posted (16)</p> <p>Uses of “Special Protection System” and<br/>“Remedial Action Scheme” in Reliability<br/>Standards (17)</p> | <p>Ballot</p> <p>Updated Info&gt;&gt;<br/>(20)</p> <p>Info&gt;&gt; (21)</p> <p>Vote&gt;&gt;</p> <p>(Closed)</p> <p>With the approval<br/>of the RAS<br/>definition,<br/>there are 43<br/>standards that have</p> | <p>07/16/14 -<br/>07/25/14</p> | <p>Summary&gt;&gt; (23)</p> <p>Ballot Results&gt;&gt;<br/>(24)</p> |   |

|   |  |                            |                                       |   |
|---|--|----------------------------|---------------------------------------|---|
| <p>RAS Definition FAQ (18)</p> <p>PRC Project Coordination Plan (19)</p>  | <p>corresponding changes to reflect the use of the single term RAS.</p>                |                            |                                       |   |
|   | <p>Comment Period Info&gt;&gt; (22)</p> <p>Submit Comments&gt;&gt;</p> <p>(Closed)</p> | <p>06/11/14 - 07/25/14</p> | <p>Comments Received&gt;&gt; (25)</p> | <p>Consideration of Comments&gt;&gt; (26)</p> |
|   | <p>Join Ballot Pool&gt;&gt;</p> <p>(Closed)</p>  | <p>06/11/14 - 07/10/14</p> |                                       |   |
| <p><b>Informal Comment Period for SCPS Revised Definition of SPS</b></p> <p>Revised SPS Definition (7)</p> <p><b>Supporting Documents:</b><br/>Unofficial Comment Form (Word) (8)</p>                 | <p>Comment Period Info&gt;&gt; (9)</p> <p>Submit Comments&gt;&gt;</p> <p>(Closed)</p>  | <p>03/11/14 - 04/09/14</p> | <p>Comments Received&gt;&gt; (10)</p> |   |
| <p><b>Standard Authorization Request (1)</b></p> <p><b>Supporting Documents:</b><br/>Unofficial Comment Form (Word) (2)</p> <p>SPCS Technical Report (3)</p> <p>PRC Project Coordination Plan (4)</p> | <p>Comment Period Info&gt;&gt; (5)</p> <p>Submit Comments&gt;&gt;</p> <p>(Closed)</p>  | <p>02/18/14 - 03/19/14</p> | <p>Comments Received&gt;&gt; (6)</p>  |   |

## Standards Authorization Request Form

When completed, email this form to:

[Valerie.Agnew@nerc.net](mailto:Valerie.Agnew@nerc.net)

For questions about this form or for assistance in completing the form, call Valerie Agnew at 404-446-2566.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

### Request to propose a new or a revision to a Reliability Standard

|   |   |         |                      |
|---|---|---------|----------------------|
| Proposed Project Number and Name                                  | Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)  |         |                      |
| Proposed Project Purpose:   | Revise NERC Glossary of Terms definition: Special Protection System (SPS)<br>Revise SPS-related Reliability Standards |         |                      |
| Date Submitted:   | 02/12/2014  |         |                      |
| SAR Requester Information   |   |         |                      |
| Name:   | Al McMeekin   |         |                      |
| Organization:   | NERC  |         |                      |
| Telephone:  | 404-446-9675  | E-mail: | Al.McMeekin@nerc.net |
| SAR Type (Check as many as applicable)                            |   |         |                      |
| <input type="checkbox"/> New Standard                             | <input checked="" type="checkbox"/> Withdrawal of existing Standard   |         |                      |
| <input checked="" type="checkbox"/> Revision to existing Standard | <input type="checkbox"/> Urgent Action  |         |                      |

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or, as used in the Western Interconnection, a Remedial Action Scheme (RAS), lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified three of the SPS-related standards (PRC-012-0, PRC-013-0, and PRC-014-0) as fill-in-the-blank standards because they are applicable to the Regional Reliability Organizations (RROs). Consequently, the Commission did not approve or remand them, rendering them neither mandatory nor enforceable.

This project also addresses, in part, four recommendations related to identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event.

NOTE: Detailed information is included in the NERC Planning Committee report “Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards” Revision 0.1 – April 2013.

Purpose or Goal (How does this request propose to address the problem described above?):

- 1) Establish a definition of an SPS that provides the specificity needed to consistently identify and classify protection schemes as SPS or RAS across all eight NERC Regions, thereby promoting the consistent application of the NERC Reliability Standards related to SPS.
- 2) Correct the applicability of the NERC Reliability Standards related to SPS by assigning responsibilities to the specific users, owners, and operators of the Bulk-Power System rather than the RROs.
- 3) Develop continent-wide standards to address all aspects of SPS, including but not limited to, the:
  - planning, coordination, and design of SPS,
  - review, assessment, and documentation of SPS,
  - operational considerations for monitoring, status notification, and response to failures,
  - analysis of SPS operations, and defining and reporting of SPS misoperations,
  - testing of SPS and maintenance of non-protection system components used in SPS.

Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):

Successful implementation of a modified SPS definition and revised SPS standards will improve Bulk-

SAR Information

Power System reliability by providing continent-wide consistency in the identification and classification of SPS and the application of NERC Reliability Standards related to SPS.

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

The project will develop a revised definition of SPS or RAS, as well as standards that address the:

- review of new or modified SPS,
- annual assessments of SPS in transmission planning studies,
- periodic comprehensive SPS assessments,
- analysis and reporting of SPS misoperations,
- maintenance, testing and operational aspects of SPS.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The SDT will revise the definition of SPS to provide the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions.

The SDT will revise or retire the six existing SPS standards:

- PRC-012-0 Special Protection System Review Procedure
- PRC-013-0 Special Protection System Database
- PRC-014-0 Special Protection System Assessment
- PRC-015-0 Special Protection System data and Documentation
- PRC-016-0.1 Special Protection System Misoperations
- PRC-017-0 Special Protection System Maintenance and Testing

The SDT will correct the applicability in PRC-012-0, PRC-013-0, and PRC-014-0 by assigning the requirements to the specific users, owners, and operators of the bulk power system.

The SDT will combine appropriate requirements from PRC-012-0, PRC-013-0, PRC-014-0, and PRC-015-0 into a Reliability Standard. The new standard will provide specific requirements for:

- review of new or modified SPS;
- annual assessments of SPS in transmission planning studies;
- periodic comprehensive SPS assessments;
- design of SPS; and



SAR Information

- coordination of SPS with other SPS, UFLS, UVLS, and Protection Systems.

Due to the significant difference between Protection Systems and SPS, the subject of SPS misoperation is not addressed in the revision of Reliability Standard PRC-004. This SDT will develop a definition for SPS misoperation and revise PRC-016-0.1. The new Reliability Standard will provide specific requirements for the analysis of SPS operations and reporting of SPS misoperations.

The SDT will address the complexity of maintaining and testing SPS, as well as the maintenance and testing of non-Protection System components used in SPS in a Reliability Standard. This SDT will coordinate with the PRC-005-4 SDT to prevent any overlaps or gaps in coverage.

The SDT also will consider operational considerations for monitoring, status notification, and response to failures of SPS; and, if necessary, modify other related standards.

The SDT will retire requirements that are administrative in nature that are not necessary for reliability of the Bulk-Power System, or that are superseded by other requirements; i.e., the new Reliability Standards will qualify as steady-state.

No market interface impacts are anticipated.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

|   |   |
|---|---|
| <input type="checkbox"/> Regional Reliability Organization  | Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions. |
| <input checked="" type="checkbox"/> Reliability Coordinator | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.  |
| <input checked="" type="checkbox"/> Balancing Authority     | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.                                       |
| <input type="checkbox"/> Interchange Authority              | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.                   |

| Reliability Functions                                     |   |
|---|---|
| <input checked="" type="checkbox"/> Planning Coordinator  | Assesses the longer-term reliability of its Planning Coordinator Area.  |
| <input type="checkbox"/> Resource Planner                 | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.   |
| <input checked="" type="checkbox"/> Transmission Planner  | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.         |
| <input type="checkbox"/> Transmission Service Provider    | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff). |
| <input checked="" type="checkbox"/> Transmission Owner    | Owns and maintains transmission facilities.   |
| <input checked="" type="checkbox"/> Transmission Operator | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.   |
| <input checked="" type="checkbox"/> Distribution Provider | Delivers electrical energy to the End-use customer.   |
| <input checked="" type="checkbox"/> Generator Owner       | Owns and maintains generation facilities.   |
| <input checked="" type="checkbox"/> Generator Operator    | Operates generation unit(s) to provide real and reactive power.   |
| <input type="checkbox"/> Purchasing-Selling Entity        | Purchases or sells energy, capacity, and necessary reliability-related services as required.  |
| <input type="checkbox"/> Market Operator                  | Interface point for reliability functions with commercial functions.  |
| <input type="checkbox"/> Load-Serving Entity              | Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.   |

| Reliability and Market Interface Principles               |   |
|---|---|
| Applicable Reliability Principles (Check all that apply). |   |
| <input checked="" type="checkbox"/>                       | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.     |
| <input type="checkbox"/>                                  | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.           |
| <input checked="" type="checkbox"/>                       | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems |

Reliability and Market Interface Principles

|  |   |                |
|--|---|----------------|
|  | reliably.   |                |
| <input checked="" type="checkbox"/>  | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.   |                |
| <input checked="" type="checkbox"/>  | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.  |                |
| <input type="checkbox"/>   | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.  |                |
| <input checked="" type="checkbox"/>  | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.  |                |
| <input type="checkbox"/>   | 8. Bulk power systems shall be protected from malicious physical or cyber attacks.  |                |
| Does the proposed Standard comply with all of the following Market Interface Principles? |   | Enter (yes/no) |
| 1.   | A reliability standard shall not give any market participant an unfair competitive advantage.   | Yes            |
| 2.   | A reliability standard shall neither mandate nor prohibit any specific market structure.  | Yes            |
| 3.   | A reliability standard shall not preclude market solutions to achieving compliance with that standard.  | Yes            |
| 4.   | A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes            |

Related Standards

| Standard No. | Explanation   |
|--------------|---|
| IRO-005-3.1a | The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.  |
| PRC-001-1.1  | The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.  |
| PRC-005-2    | The SDT may decide not to change this standard, or subsequently approved versions, but the SDT should keep the standard in mind to avoid any gaps or overlap between this standard and PRC-017-1. |

| Related Standards |             |
|-------------------|-------------|
|                   |             |
| Related SARs      |             |
| SAR ID            | Explanation |
|                   |             |
|                   |             |
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| Regional Variances |             |
|--------------------|-------------|
| Region             | Explanation |
| ERCOT              |             |
| FRCC               |             |
| MRO                |             |
| NPCC               |             |
| RFC                |             |
| SERC               |             |
| SPP                |             |
| WECC               |             |

## Unofficial Comment Form

### Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) – SAR

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by **8 p.m. ET March 19, 2014**.

If you have questions please contact [Al.McMeekin@nerc.net](mailto:Al.McMeekin@nerc.net) via email or by telephone at 404-446-9675.

The project page may be accessed by [clicking here](#). (Please insert link to new project page)

#### Background Information

In early 2011, NERC staff decided to divide the approved project for Protection System Misoperations into two phases. Phase 1 of Project 2010-05 is addressing Misoperations of Protection Systems; the project began in April, 2011 and is ongoing. Project 2010-05.2 Special Protection Systems is Phase 2 of Protection Systems and will address all aspects of Special Protection Systems including misoperations of SPS. In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as “fill-in-the-blank” standards and did not approve or remand them because they are applicable to the Regional Reliability Organizations (RROs); consequently, they are not mandatory or enforceable. This project proposes to correct the applicability by assigning responsibilities to the specific users, owners, and operators of the Bulk-Power System. The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or Remedial Action Scheme (RAS), as used in the Western Interconnection, lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions. This leads to inconsistent application of the SPS-related Reliability Standards. At the request of the NERC Standards Committee, the Planning Committee directed the System Protection and Control Subcommittee (SPCS) to research this issue. The SPCS authored the attached report and provided a draft definition of SPS for consideration in the standards development process. This project proposes to establish a definition for SPS that provides the needed specificity to promote the consistent application of the NERC Reliability Standards related to SPS. This project also proposes to address, in part, four recommendations related to identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event. There is no FERC directive associated with the SPS project; however, this project is being coordinated with Project 2008-02 UVLS, which does have an associated directive in P 1509 of Order No. 693 to modify PRC-010-0. These projects are linked because the proposed definition for Special Protection Systems must be written relative to the proposed definition of UVLS Program.

## Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Do you have any specific questions or comments relating to the scope of the proposed SAR?

Yes

No

Comments:

2. If you are aware of the need for a regional variance or business practice that should be considered with this phase of the project, please identify it here.

Yes

No

Comments:

3. If you have any other comments on this SAR that you haven't already mentioned, please provide them here:

Comments:

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards

Revision 0.1 – April 2013

**RELIABILITY | ACCOUNTABILITY**



3353 Peachtree Road NE  
Suite 600, North Tower  
Atlanta, GA 30326  
404-446-2560 | [www.nerc.com](http://www.nerc.com)

# NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.<sup>1</sup>

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



**Note:** The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

| NERC Regional Entities                                  |   |
|---|---|
| <b>FRCC</b><br>Florida Reliability Coordinating Council | <b>SERC</b><br>SERC Reliability Corporation             |
| <b>MRO</b><br>Midwest Reliability Organization          | <b>SPP RE</b><br>Southwest Power Pool Regional Entity   |
| <b>NPCC</b><br>Northeast Power Coordinating Council     | <b>TRE</b><br>Texas Reliability Entity                  |
| <b>RFC</b><br>ReliabilityFirst Corporation              | <b>WECC</b><br>Western Electricity Coordinating Council |

<sup>1</sup> As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC’s reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.



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*This technical document was approved by the NERC Planning Committee on March 5, 2013.*

## Executive Summary

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The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration. A request for research was submitted by the Standards Committee on January 9, 2012 (see Appendix D). The Planning Committee had already approved a joint effort by the System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) <sup>2</sup> on June 8, 2011 (see Appendix E) which includes issues identified in the request for research. This report addresses all issues identified in the scope of the joint SAMS and SPCS project as well as the Standards Committee request for research; upon approval by the Planning Committee the report should be forwarded to the Standards Committee to support Project 2010-05.2.

This report includes recommendations for a new definition of SPS and revisions to the six SPS-related PRC standards. A strawman definition is provided that eliminates ambiguity in the existing definition and identifies 13 types of schemes that are not SPS, but for which uncertainty has existed in the past based on experience within the Regions. The report also recommends that SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed.

This report provides recommendations to address FERC concerns with PRC-012-0, PRC-013-0, and PRC-014-0, which assign requirements to Regional Reliability Organizations. Recommendations are made to reassign requirements to specific users, owners, and operators of the bulk power system to remedy this situation.

Project 2010-05.2 should consolidate the requirements pertaining to review, assessment, and documentation of SPS into one standard that includes continent-wide procedures for reviewing new or modified SPS, for assessing existing SPS in annual transmission planning assessments, and for periodic comprehensive SPS assessments. The project also should revise requirements pertaining to analysis and reporting of SPS misoperations in a revision of standard PRC-016-0.1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004. Given the scope of work and need for drafting team members with different subject matter expertise it may be appropriate to sub-divide Project 2010-05.2 to address review, assessment and documentation of SPS separately from analysis and reporting of misoperations. This report also provides recommendations for Standards Committee consideration that are outside the scope of Project 2010-05.2. These additional recommendations pertain to maintenance and testing and operational aspects of SPS.

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<sup>2</sup> The original scope of work involved the SPCS and the predecessor of SAMS, the Transmission Issues Subcommittee (TIS).

# Introduction

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## Problem Statement

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration.

## Background

### NERC Definitions

The existing NERC *Glossary of Terms* defines an SPS and RAS as:

#### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

In this document, use of the term SPS in general discussions and proposals for future definitions and standards apply to both SPS and RAS. Specific references to existing practices within Regions use the term SPS or RAS as appropriate for that Region.

The NERC *Glossary of Terms* defines a Protection System as:

#### *Protection System*

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Inclusion of the words “protection system” in the term Special Protection System has raised questions whether this is an intentional reference such that SPS are a subset of Protection Systems. Use of protection system (lower case) within the SPS definition identifies that SPS are not Protection Systems. While SPS may include the same types of components as Protection Systems, SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment. SPS may, for example, effect a change to the operating state of power system elements to preserve system stability or to avoid unacceptable voltages or overloads in response to system events. There are many reasons for implementing an SPS; for example, an SPS can be implemented to ensure compliance with the TPL Reliability Standards, to mitigate temporary operating conditions or abnormal configurations (e.g., during construction or maintenance activities), or in instances where system operators would not be able to respond quickly enough to avoid adverse system conditions.

A second area in which the existing SPS definition lacks clarity is the actions that are characteristics of SPS. The actions listed in the definition are broad and may unintentionally include equipment whose purpose is not expressly related to preserving system reliability in response to an event. Inclusion of any system taking “corrective action other than ... isolation of faulted components to maintain system reliability” could be deemed to include equipment such as voltage regulators and switching controls for shunt reactive devices. This inclusion would then make these elements subject to single component failure considerations (sometimes referred to as redundancy considerations), coordination, reporting, and maintenance and testing requirements that may be required in the NERC Reliability Standards related to SPS.

This report proposes a revised definition of SPS to address these issues. Development of the proposed definition considered other definitions, common applications, and existing practices regarding classification of SPS.

### **NERC Reliability Standards**

The NERC Reliability Standards contain six standards in the protection and control (PRC) series that specifically pertain to SPS.

- PRC-012-0: Special Protection System Review Procedure
- PRC-013-0: Special Protection System Database
- PRC-014-0: Special Protection System Assessment
- PRC-015-0: Special Protection System Data and Documentation
- PRC-016-0.1: Special Protection System Misoperations
- PRC-017-0: Special Protection System Maintenance and Testing

Three of these standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*. These standards assign the Regional Reliability Organizations responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of SPS. The deference to regional practices, coupled with lack of clarity in the definition of SPS, preclude consistent application of requirements pertaining to SPS. This report provides recommendations that may be implemented through the NERC Reliability Standards Development Process to consolidate the standards and provide greater consistency and clarity regarding requirements.

# Chapter 1 – SPS Definition

## Considerations for a Revised Definition

### Other Definitions in Industry

Several IEEE papers<sup>3</sup> define a similar term to SPS: System Integrity Protection System (SIPS). Adopting the SIPS definition is not appropriate because it is more inclusive than NERC’s definition:

“The SIPS encompasses special protection system (SPS), remedial action schemes (RAS), as well as other system integrity schemes, such as underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc.”<sup>4</sup>

NERC applies special consideration to UF and UV load shedding schemes in the Reliability Standards and considers OOS relaying in the context of traditional protection systems. Thus, SIPS is not an appropriate term for use in the Reliability Standards, and a new definition of SPS is more appropriate.

### Common Application of SPS in Industry

Most SPS are used to address a range of system issues including stability, voltage, and loading concerns. Less common applications include arresting sub-synchronous resonance and suppressing torsional oscillations. Actions taken by SPS may include (but are not limited to): system reconfiguration, generation rejection or runback, load rejection or shedding, reactive power or braking resistor insertion, and runback or fast ramping of HVdc.

SPS are often deployed because the operational solutions they facilitate are substantially quicker and less expensive to implement than construction of transmission infrastructure. Permanent SPS have been implemented in some cases where the cost associated with system expansion is prohibitive, construction is not possible due to physical constraints, or obtaining permits is not feasible. In other cases temporary SPS have been implemented to maintain system reliability until transmission infrastructure is constructed; or when a reliability risk is temporary (e.g., during equipment outages) and the expense associated with permanent transmission upgrades is not justified.

The deployment of SPS adds complexity to power system operation and planning:

“Although SPS deployment usually represents a less costly alternative than building new infrastructure, it carries with it unique operational elements among which are: (1) risks of failure on demand and of inadvertent activation; (2) risk of interacting with other SPS in unintended ways; (3) increased management, maintenance, coordination requirements, and analysis complexity.”<sup>5</sup>

Subsequent sections of this report consider these three operational elements and provide recommendations regarding how they should be addressed in the NERC Reliability Standards. A summary of the number of schemes identified as SPS or RAS by Region is provided below.

| Region | Total Number | Region | Total Number |
|--------|--------------|--------|--------------|
| FRCC   | 20           | SERC   | 20           |
| MRO    | 36           | SPP    | 6            |
| NPCC   | 117          | TRE    | 24           |
| RFC    | 47           | WECC   | 192          |

<sup>3</sup> One notable reference, Madani, et al, “IEEE PSRC Report on Global Industry Experiences with System Integrity Protection Schemes (SIPS),” IEEE Trans. on Power Delivery, Vol. 25, Oct. 2010.

<sup>4</sup> *Ibid.*

<sup>5</sup> McCalley, et al, “System Protection Schemes: Limitations, Risks, and Management”, PSERC Publication 10-19, Dec 2010.

<sup>6</sup> Numbers for 2011 obtained from data reported in the NERC Reliability Metric ALR6-1.

## Classification of SPS Types

Three regions classify SPS according to various criteria, including the type of event the SPS is designed to address as well as the ability of the SPS to impact on a local versus wide-area reliability. The following information describes how NPCC, WECC and TRE classify SPS. Please note that examples of regional practices are provided for illustration throughout this document, but are not necessarily best practices or applicable to all Regions. Also in this context, what constitutes local versus wide-area varies among Regions and is not based on the NERC glossary term Wide Area, which is specific to calculation of Interconnection Reliability Operating Limits (IROL).<sup>7</sup>

### *NPCC*

**Type I** – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. The corrective action taken by the Special Protection System along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.

**Type II** – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.

**Type III** – A Special Protection System whose misoperation or failure to operate results in no significant adverse impact outside the local area.

The following terms are also defined by NPCC to assess the impact of the SPS for their classification:

**Significant adverse impact** – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

- a. system instability;
- b. unacceptable system dynamic response or equipment tripping;
- c. voltage levels in violation of applicable emergency limits;
- d. loadings on transmission facilities in violation of applicable emergency limits;
- e. unacceptable loss of load.

**Local area** – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

### *WECC*

**Local Area Protection Scheme (LAPS):** A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss  $\geq$  300 MW,
- Maximum generation loss  $\geq$  1000 MW.

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<sup>7</sup> The NERC Glossary defines Wide Area as “The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.”

**Wide Area Protection Scheme (WAPS):** A Remedial Action Scheme (RAS) whose failure to operate WOULD result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss  $\geq$  300 MW,
- Maximum generation loss  $\geq$  1000 MW.

**Safety Net:** A type of Remedial Action Scheme designed to remediate TPL-004-0 (System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)), or other extreme events.

**TRE:**

- (a) A “Type 1 SPS” is any SPS that has wide-area impact and specifically includes any SPS that:
  - (i) Is designed to alter generation output or otherwise constrain generation or imports over DC Ties; or
  - (ii) Is designed to open 345 kV transmission lines or other lines that interconnect Transmission Service Providers (TSPs) and impact transfer limits.
- (b) A “Type 2 SPS” is any SPS that has only local-area impact and involves only the facilities of the owner-TSP.

These three regional classifications can be roughly mapped:

- NPCC Type I = WECC WAPS = TRE Type 1
- NPCC Type III = WECC LAPS = TRE Type 2
- NPCC Type II = WECC Safety Net

SPS classification differentiates the reliability risk associated with SPS and provides a means to establish more or less stringent requirements consistent with the reliability risk. For example, it may be appropriate to establish less stringent requirements pertaining to monitoring or single component failure of SPS that present a lower reliability risk. A recommendation for classification of SPS is included with the proposed definition and subsequent discussion of standard requirements includes recommendations where different requirements based on classification are deemed appropriate.

### Common Exclusions from the SPS Definition in Industry

Exclusions provide a means to assure that specific protection or control systems are not unintentionally included as SPS. The NERC glossary definition of SPS states that “An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS).”

Even with the exclusions in the NERC definition, other commonly applied protection and control systems meet the general language in the SPS definition. Considerable effort has been expended by industry discussing what systems are SPS. NPCC and SERC have documented examples of exclusions to the SPS definition in their regional guidelines. NPCC explicitly excludes “Automatic underfrequency load shedding; Automatic undervoltage load shedding and manual or automatic locally controlled shunt devices.”<sup>8</sup> SERC’s SPS guideline calls out specific exclusions as follows:

- a. UFLS and/or UVLS,
- b. Fault conditions that must be isolated including bus breakup / backup / breaker failure protection,
- c. Relays that protect for specific equipment damage (such as overload, overcurrent, hotspot, reclose blocking, etc.),
- d. Out of step relaying,
- e. Capacitor bank / reactor controls,

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<sup>8</sup> NPCC *Glossary of Terms Used by Directories*



- f. Load Tap Changer (LTC) controls,
- g. Automated actions that could be performed by an operator in a reasonable amount of time, including alternate source schemes, and
- h. Scheme that trips generation to prevent islanding

A recommended list of protection and control systems that should be excluded from classification as SPS is included with the proposed definition.

### Exclusion for Operator Aides

SAMS and SPCS considered a number of factors in discussing this subject including:

- 1) whether the actions are required to be completed with such urgency that it would be difficult for an operator to react and execute in the necessary time, and
- 2) whether the required actions are of such complexity or across such a large area that it would be difficult for an operator to perform the actions in the necessary time.

It is difficult to address these questions with concise and measurable terms, making it difficult to explicitly exclude them in the definition without introducing ambiguous terms counter to the objective of providing needed clarity in the SPS definition. Whether its existence is based upon convenience or not, any automated system with the potential to impact bulk power system reliability should be defined and expressed to the appropriate authority (e.g., Planning Coordinator, Reliability Coordinator) for the purposes of system modeling and coordination studies, to ensure that these systems are properly coordinated with other protection and control systems, and to ensure that inadvertent operations do not result in adverse system impacts.

On these bases, SAMS and SPCS decided not to provide an exclusion for schemes based on a general criterion as to whether the scheme automates actions that an operator could perform in a reasonable amount of time or schemes installed for operator convenience. However, SAMS and SPCS do recommend exclusions for specific applications that meet these criteria such as automatic sequences that are initiated manually by an operator. Furthermore, any scheme that is not installed “to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, an extreme event, or Cascading” would be excluded by definition, regardless of whether it is installed to assist an operator.

### Voltage Threshold

All elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.

### Proposed Definition

The proposed definition clarifies the areas that have been interpreted differently between individual entities and within Regions, in some cases leading to differing regional definitions of SPS. The proposed definition provides a framework for differentiating among SPS with differing levels of reliability risk and will support the drafting of new or revised SPS standards.

#### *Special Protection System (SPS)*

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

- a) Underfrequency or undervoltage load shedding
- b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature
- c) Autoreclosing schemes
- d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers
- e) Schemes that prevent high line voltage by automatically switching the affected line
- f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open
- g) Out-of-step relaying
- h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty
- j) Automatic sequences that proceed when manually initiated solely by an operator
- k) Sub-synchronous resonance (SSR) protection schemes
- l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards.

- Type PS (planning-significant): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type PL (planning-limited): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.
- Type ES (extreme-significant): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type EL (extreme-limited): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.

An SPS is classified as having a significant impact on the BES if failure or inadvertent operation of the scheme results in any of the following:

- Non-Consequential Load Loss  $\geq$  300 MW

- Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection<sup>9</sup>
- Loss of synchronism between two or more portions of the system each including more than one generating plant
- Negatively damped oscillations

If none of these criteria are met, the SPS is classified as having a limited impact on the BES.

## Definition of Significant and Limited Impact

The parameters used to define the bright line between “significant” and “limited” impacts are proposed to consider only the electrical scale of the event. Defining the bright line in this way eliminates the difficulty in distinguishing the geographic impact of an SPS as either “wide” or “local.”

NERC Standard EOP-004-1, DOE Form OE-417 Electric Emergency Incident and Disturbance Report, establishes the criteria by which an event is categorized as a Disturbance and requires a disturbance report. In terms of SPS, the proposed criteria for significant impact mirrors EOP-004-1 by including a non-consequential load loss value of 300 MW.

NERC Reliability Standards require consideration of loss of any generating unit; therefore, generating unit loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the interconnection. The generation loss level was selected as a loss greater than the largest unit within an interconnection on this basis.

Tripping multiple generating units exceeding the capacity of the largest unit within an interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requiring detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators, combined with the loss of load criterion, are proposed to identify the potential reliability risk associated with failure of a SPS. Subsequent sections of this report recommend requirements for assessment and design of SPS based on whether the potential reliability risk associated with the SPS are significant versus limited impacts.

The proposed thresholds differentiate between significant and limited impact. While it should be clear there is no upper threshold on what constitutes a significant impact, there also is no lower threshold proposed as to what constitutes limited impact. Whether a scheme is an SPS is determined by the definition; significant and limited impact are used only to classify SPS. For example, if a scheme is installed to meet system performance requirements identified in the NERC Reliability Standards then it is an SPS regardless of its potential impact. A failure of the SPS would result in a violation of a NERC Reliability Standard. Thus, excluding a scheme with impact below a certain threshold would undermine the reliability objective of the standard requirement the scheme is installed to address.

<sup>9</sup> I.e., Eastern, Western, ERCOT, or Quebec Interconnection.

# Chapter 2 – Design and Maintenance Requirements

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Under the proposed definition, SPS are implemented to preserve acceptable system performance, and as such may be critical to power system reliability and therefore subject to single component failure considerations, and maintenance and testing requirements outlined in the PRC standards.

## General Design Considerations

Aside from the single component failure, and maintenance and testing considerations outlined below, Disturbance Monitoring Equipment should be provided in the design of an SPS to permit analysis of the SPS performance following an event. Also, as with other automated systems, the design of an SPS should facilitate its maintenance and testing.

## SPS Single Component Failure Requirements

Requirement R1.3 in PRC-012-0 requires SPS owners to demonstrate an SPS is designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0. This requirement should be retained in future standards such that Types PS and PL SPS are required to be designed so that power system performance meets the performance requirements of TPL-001-0, TPL-002-0, or TPL-003-0, in the event of a single component failure. The design of Type PS and PL SPS can provide the required performance through any of the methods outlined below, or a combination of these methods:

1. Arming more load or generation than necessary to meet the intended results. Thus the failure of the scheme to drop a portion of load or generation would not be an issue. In this context it is necessary to arm the tripping of more load delivery points or generating units rather than simply arming more MW of load or generation. When this option is used, studies of the SPS design must demonstrate that tripping the total armed amount of load or generation will not cause other adverse impacts to reliability.
2. Providing redundancy of SPS components listed below.
  - Any single ac current source and/or related input to the SPS. Separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing should be considered an acceptable level of redundancy.
  - Any single ac voltage source and/or related input to the SPS. Separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device should be considered an acceptable level of redundancy.
  - Any single device used to measure electrical quantities used by the SPS.
  - Any single communication channel and/or any single piece of related communication equipment used by the SPS.
  - Any single computer or programmable logic device used to analyze information and provide SPS operational output.
  - Any single element of the dc control circuitry that is used for the SPS, including breaker closing circuits.
  - Any single auxiliary relay or auxiliary device used by the SPS.
  - Any single breaker trip coil for any breaker operated by the SPS.
  - Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

3. Using remote or time delayed actions such as breaker failure protection<sup>10</sup> or alternative automatic actions to back up failures of single components (e.g., an independent scheme that trips an element if an overload exists for longer than the time necessary for the SPS to take action). The backup operation would still need to provide mitigation to meet the necessary result in the required timeframe.
4. For Type PL SPS, manual backup operation may be used to address the failure of a single SPS component if studies are provided to show that implemented procedures will be effective in providing the required response when a SPS failure occurs. The implemented procedures will include alarm response and manual operation time requirements to provide the backup functions.

Some SPS utilize an Energy Management System (EMS) system for transmitting signals or calculating information necessary for SPS operation such as the amount of load or generation to trip. Loss of the EMS system must be considered when assessing the impact of a single component failure. For example, when the EMS is used to transmit a signal, a separate communication path must be available. When a non-redundant EMS provides a calculated value to two otherwise independent systems, a backup calculation or default value must be provided to the SPS in the event of an EMS failure.

Types ES and EL SPS are designed to provide system protection against extreme events. The events that Types ES and EL SPS are intended to address have a lower probability of occurrence and the TPL standards do not require mitigation for these events. Dependability of SPS operation is therefore not critical for these events and, consistent with the existing standards, these SPS should not be required to perform their protection functions even with a single component failure. Design requirements for Type ES SPS should emphasize security; however, in some cases Type ES SPS are installed to address an event with consequences so significant (e.g., system separation or collapse of an interconnection) that consideration should be given to both dependability and security. In consideration that the addition of redundancy in some cases might make the SPS less secure, such cases may warrant implementation of a voting scheme<sup>11</sup>.

## Maintenance and Testing

The Project 2007-17, Protection System Maintenance and Testing, drafting team revised PRC-005 to include maintenance and testing requirements for SPS contained in PRC-017-0.<sup>12</sup> All of the existing requirements in PRC-017-0 that are based on a reliability objective are mapped to PRC-005-2. However, this report identifies two subjects that are not covered in either the existing standard or the proposed standard:

- Complex SPS require different procedures than those used for maintenance of protection systems.
- Maintenance of non-protection system components used in SPS is not addressed in any existing NERC Reliability Standards.

These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

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<sup>10</sup> In this context it is not intended that breaker failure protection must be redundant; rather, that breaker failure protection may be relied on to meet the design requirements (e.g., if an SPS required tripping a breaker with a single trip coil).

<sup>11</sup> A voting scheme achieves both dependable and secure operation by requiring, for example, two out of three schemes to detect the condition prior to initiating action.

<sup>12</sup> PRC-005-2 was adopted by the NERC Board of Trustees on November 7, 2012

## Chapter 3 – Study and Documentation Requirements

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### Review and Approval of New or Modified SPS

Requirement R1 in PRC-012-0 requires each Regional Reliability Organization to have a documented review procedure to ensure that SPS comply with regional criteria and NERC Reliability Standards. However, the potential for SPS interaction and for SPS operation or misoperation to have inter-regional impacts suggests that a uniform procedure for reviewing SPS is important to ensure bulk power system reliability. This report recommends fundamental aspects that should be included in a continent-wide SPS review procedure and included in the revised reliability standards pertaining to SPS. The review process should be conducted by an entity or entities with the widest possible view of system reliability, and must be a user, owner, or operator of the bulk power system. To assure that both planning and operating views are evaluated before a new or modified SPS is placed in service, responsibility for reviewing and approving implementation of SPS should be assigned to the Reliability Coordinator and Planning Coordinator. Ideally these reviews should be performed on a regional or interconnection-wide basis. If in the future an entity is registered as the Reliability Assurer for each Region, the responsibility for performing these reviews, or alternately for coordinating these reviews, should be assigned to the Reliability Assurer.

A continent-wide review process should be established in a revised reliability standard that includes the following aspects:

- The SPS owner<sup>13</sup> should be required to obtain approval from its Reliability Coordinator and its Planning Coordinator in whose area the SPS is installed<sup>14</sup> prior to placing a new or modified SPS in service.
- An entity proposing a new or modified SPS should be required to file an application with its Reliability Coordinator and Planning Coordinator that includes the following information:
  - A document outlining the details of the SPS as specified below in the section titled, Data Submittals by Entities that Own SPS.
  - Studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. The study report should include the following:<sup>15</sup>
    - Entity conducting the SPS study
    - Study completion date
    - Study years
    - System conditions
    - Contingencies analyzed
    - Demonstration that the SPS meets criteria discussed in the Design Considerations chapter of this report
    - Discussion of coordination of the SPS with other SPS, UFLS, UVLS, and protection systems
- The Reliability Coordinator and Planning Coordinator should be required to provide copies of the application and supporting information to Transmission Planners, Transmission Operators, and Balancing Authorities within their area, and to adjacent Reliability Coordinators and Planning Coordinators.
- Entities receiving the application should be allowed to provide comments to the Reliability Coordinator and Planning Coordinator.

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<sup>13</sup> In cases where more than one entity owns an SPS, the standards should designate that a designated “reporting entity” be responsible for transmitting data to the Reliability Coordinator and Planning Coordinator, while all owners retain responsibility for other requirements such as maintenance and testing.

<sup>14</sup> In cases where an SPS has components installed in or takes action in more than one Reliability Coordinator area or Planning Coordinator area, all affected Reliability Coordinators and Planning Coordinators should have approval authority.

<sup>15</sup> The same documentation requirements should apply to Periodic Comprehensive Assessments of SPS Coordination.

- When deciding whether to approve an SPS, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is to be installed or modified should be required to consider supporting information provided with the application; comments from Transmission Planners, Transmission Operators, and Balancing Authorities and other Reliability Coordinators and Planning Coordinators; and any supplemental information provided by the SPS owner.
- The basis of the Reliability Coordinator and Planning Coordinator approval should be limited to whether all required information has been submitted and the studies are sufficient to support that all performance requirements are met.

## Assessment of Existing SPS

### Study of SPS in Annual Transmission Planning Assessments

Requirement R1 in PRC-014-0 specifically addresses assessment of the operation, coordination, and effectiveness of all SPS and assigns this responsibility to the Regional Reliability Organization. Reliability standards must assign responsibility to owners, operators, and users of the bulk power system. For assessments of SPS, it is important to identify an entity with the necessary expertise in system studies and a wide-area view to facilitate coordination of SPS across the system. Instead of assigning this responsibility to the Regional Reliability Organization or the Regional Entity, the assessment responsibility should be assigned to the Planning Coordinator and Transmission Planner for SPS within their specific area.

Annually, the Planning Coordinator and Transmission Planner should review the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. If system changes have occurred which can affect the operation of the SPS, annual studies should include system conditions and contingencies modeled in the study supporting the application for installation of or modifications to an SPS.

Any issues identified should be documented and submitted to the Reliability Coordinator and the SPS owner. The Reliability Coordinator and Planning Coordinator should be required to determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

### Periodic Comprehensive Assessments of SPS Coordination

Comprehensive assessment should occur every five years, or sooner, if significant changes are made to system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems. Responsibility for the comprehensive assessment should be assigned to the Reliability Coordinator to achieve the wide-area review necessary for a comprehensive assessment. Planning Coordinators, Transmission Planners, Transmission Operators, Balancing Authorities, and adjacent Reliability Coordinators should be required to provide support to the Reliability Coordinator when requested to do so. As part of the periodic review the Reliability Coordinator should be required to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets criteria discussed in the Design Considerations chapter of this report, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.

The Reliability Coordinator should be required to provide its periodic assessment to Planning Coordinators, Transmission Planners, Transmission Operators, and Balancing Authorities in its area, and to adjacent Reliability Coordinators, and should be required to consider comments provided by these entities. Any issues identified with an SPS should be documented and submitted to the SPS owner. If any concerns are identified, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is installed should determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

## Documentation Requirements

### Data Submittals by Entities that Own SPS

Reliability standard PRC-015-0 establishes requirements for SPS owners to provide data for existing and proposed SPS as specified in reliability standard PRC-013-0 Requirement R1. PRC-013-0 establishes the data provided shall include the following:

- Design Objectives — Contingencies and system conditions for which the SPS was designed
- Operation — The actions taken by the SPS in response to Disturbance conditions
- Modeling — Information on detection logic or relay settings that control operation of the SPS

This requirement should be carried forward to the revised standards for the SPS owner to provide detailed information regarding the conditions of SPS operation. However, this requirement should be modified to ensure that communication of this information is clear and understandable to all entities that require the information to plan and operate the bulk power system (e.g., Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities). Additional specificity should be added to this list of data to assure that sufficient information is provided for entities to understand and model SPS operation.

Since SPS design and complexity vary considerably, a brief description of the action taken when certain system conditions are detected generally does not provide a sufficient level of detail. Conversely, logic and control wiring diagrams may provide too much detail that is not readily understood except by the SPS owner's protection and control engineers. To achieve an appropriate level of detail that provides a common understanding by the SPS owner and other entities, the SPS owner should work with the Transmission Planner to develop a document outlining the details of the SPS operation specifically tailored to the needs and knowledge level of the entities that require this information to plan and operate the bulk power system. The document should include the following:

- SPS name
- SPS owner
- Expected in-service date
- Whether the SPS is intended to be permanent or temporary
- SPS classification (per revised definition), and documentation or explanation of how the SPS mitigates the planning or extreme event and why the impact is significant or limited
- Logic diagram, flow chart, or truth table documenting the scheme logic and illustrating how functional operation is accomplished
- Whether the SPS logic is:
  - Event-based<sup>16</sup>
  - Parameter-based<sup>17</sup>
  - A combination of event-based and parameter-based
- System performance criteria violation necessitating the SPS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

<sup>16</sup> Event-based schemes directly detect outages and/or fault events and initiate actions such as generator/load tripping to fully or partially mitigate the event impact. This open-loop type of control is commonly used for preventing system instabilities when necessary remedial actions need to be applied as quickly as possible.

<sup>17</sup> Parameter-based schemes measure variables for which a significant change confirms the occurrence of a critical event. This is also a form of open-loop control but with indirect event detection. The indirect method is mainly used to detect remote switching of breakers (e.g., at the opposite end of a line) and significant sudden changes which can cause instabilities, but may not be readily detected directly. To provide timely remedial action execution, the measured variables may include power, angles, etc., and/or their derivatives.



- Parameters and equipment status monitored as inputs to the SPS (e.g., voltage, current or power flow, breaker position) and specific monitoring points and locations
- Under what conditions the SPS is armed (e.g., always armed, armed for certain system conditions, actuation thresholds)
- Whether arming is accomplished automatically or manually, if required
- Arming criteria – analog quantities and/or equipment status monitored to determine existence of the system condition for which SPS is armed (e.g., generation/load patterns, reactive power reserves, facility loading)
- Action taken – for example: transmission facilities switched in or out; generators tripped, runback, or started; load dropped; tap setting changed (phase-shifting transformer); controller set-point changed (AVR, SVC, HVdc converter); turbine fast valving or generator excitation forcing; braking resistor insertion
- Time to operate, including intentional time delays (e.g., timer settings) and inherent delays (e.g., relay operating time)
- Information with sufficient detail necessary to model the SPS.

### SPS Database

PRC-013-0, Requirement R1 requires the Regional Reliability Organization to maintain an SPS database, including data on design objectives, operation, and modeling of each SPS. Similar to the other requirements presently assigned to the Regional Reliability Organization, this requirement should be assigned to a user, owner, or operator of the bulk power system. To minimize the number of databases and facilitate sharing of information with entities that require SPS data to plan and operate the bulk power system, this requirement should be assigned to the Planning Coordinator. The Planning Coordinator should be required to provide its database to NERC for the purpose maintaining a continent-wide data base<sup>18</sup> that NERC would make available to Reliability Coordinators, Transmission Operators, Balancing Authorities, Planning Coordinators, and Transmission Planners that require this data. The database should contain information for each SPS as described above in the section titled, Data Submittals by Entities that Own SPS.

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<sup>18</sup> The requirement in a NERC Reliability Standard would be applicable to the Planning Coordinator; the responsibility for NERC to maintain a continent-wide database should be addressed outside the standard.

## Chapter 4 – Operational Requirements

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Due to their unique nature, SPS may have special operational considerations, with potentially differing requirements among the proposed types for monitoring, notification of status, and the response time required to address SPS failure. Furthermore, consideration should be given to the documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.

One entity should be assigned primary responsibility for monitoring, coordination, and control of an SPS. Depending on the complexity, this responsible party may be a Reliability Coordinator, Balancing Authority, or Transmission Operator. Complex SPS may have multiple owners or affected entities, including different functional entities and the chain of notification and control should be clearly established.

### Monitoring of Status

Existing NERC Reliability Standard IRO-005-3.1a, Requirement R1.1 requires Reliability Coordinators to monitor SPS. Similarly PRC-001-1, Requirement R6 requires Balancing Authorities and Transmission Operators to monitor SPS. The SPS standards should establish the level of monitoring capability that must be provided by the SPS owner. Classification of the SPS will dictate its design criteria and may lend itself to different levels of monitoring.

All SPS should be monitored by SCADA/EMS with real-time status communicated to EMS that minimally includes whether the scheme is in-service or out-of-service, and the current operational state of the scheme. For SPS that are armed manually the arming status may be the same as whether the SPS is in-service or out-of-service. For SPS that are armed automatically these two states are independent because an SPS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met. In cases where the classification of the SPS requires redundancy, the minimal status indications should be provided for each system. The minimum status is sufficient for operational purposes; however, where possible it may be useful to provide additional information regarding partial failures or the status of critical components to allow the SPS owner to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the SPS. While all schemes should be required to provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring similar to what is provided for microprocessor-based protection systems.

Similarly, the SCADA/EMS presentation to the operator would need to indicate the criticality of the scheme (e.g., through the use of audible alarms and a high priority in the alarm queue). The operator would be expected to know how to respond depending on the nature of the issue detected, as some partial SPS failures might not result in a complete failure of the scheme.

In cases where SPS cross ownership and operational boundaries, it is important that all entities involved with the SPS are provided with an appropriate level of monitoring.

### Notification of Status

Since the owner and operator of an SPS or component are often different organizations, and because SPS may cross entity boundaries, it is important that the SPS status is communicated appropriately between entities. Existing NERC Reliability Standards already require some level of notification of SPS status by Reliability Coordinators, Balancing Authorities and Transmission Operators.<sup>19</sup> Furthermore, SPS owners (e.g., Transmission Owner, Generator Owner) should be responsible for communicating scheme or component issues to the operating organizations (e.g., Transmission Operator, Generator Operator), who should then be responsible for communicating the issues to the involved Reliability Coordinator, Balancing Authority, and other Transmission Operators or Generator Operators that might rely on the SPS (for example, in setting operating limits).

The required timing associated with such notification will depend on the type of scheme; for example, the misoperation of a Type PS or ES scheme would require rapid notification to all interested parties. In general, the more critical a scheme is to the reliability of the system, the then more important its notification and response; however, it is also important that some

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<sup>19</sup> See, for example, IRO-005-3.1a Requirement R9 and PRC-001-1, Requirement R6.

level notification be made for all schemes, due to the complex nature of SPS and their interaction with each other, to allow entities to understand the reliability impact of a neighboring entity's SPS failure or misoperation.

## Response to Failures

As with many of the other issues, the response time required to address SPS failure is tightly coupled to the potential impact of the SPS as well as the operating conditions at the time of failure. For example, if the SPS is intended to address an event with a significant impact such as an IROL, then any corrective action in response to a misoperation would need to be taken in 30 minutes or less, consistent with the  $T_v^{20}$  associated with the IROL. On the other hand, depending on the operating conditions, a particular scheme's unavailability may not result in an adverse impact to reliability. Actions taken following an SPS failure should consider whether the failure affects dependability or security of the SPS and the potential impact to reliability.

Generally speaking, the SPS failure modes are known and the necessary corrective actions are documented (e.g., contingency plans) so that the system can be placed in a safe operating state. In any case, a full or partial failure of an SPS requires that the system performance level provided by having the SPS in service is met, or a more conservative and safe operating condition would need to be achieved, in a timeframe appropriate for the nature of the SPS and operating conditions. When one system of a redundant SPS fails, the action taken by the operator may depend on the system conditions the SPS is installed to address and the operating conditions at the time of the failure. For example, an operator may respond to failure of one system by operating to higher equipment ratings when an SPS is installed to address thermal loading violations. However, the operator may not be able to rely on the remaining system of a redundant SPS when the SPS is installed to prevent instability, system separation, or cascading outages, in which case the operator must reduce transfers or take other actions to secure the system.

## Operational Documentation

Operational documentation is necessary to provide the operator with enough information to understand all aspects of the scheme and is used to provide knowledge transfer as staff changes occur. Overall documentation requirements are identified in the section on Study and Documentation Requirements; however, the operator does not require all information provided by the SPS owner for the database maintained by the Planning Coordinator. The operational documentation is sometimes called a "description of operations" and provides the operation actions for the following areas:

- General Description – This provides an overview of the purpose of the scheme including the monitoring, set points and actions of the scheme. The operator and other stake holders can use this information to understand the need for the scheme.
- Operation – This will provide the specific information concerning, arming, alarming, and actions taken by this scheme including the monitoring points of the scheme. The operator can use this information to provide triage and plan a course of action concerning restoration of the electric system. This information should provide an understanding of what has operated, why these elements have been impacted, and possible mitigations or restoration activities.
- Failures, Alarms, Targeting – This information will provide the operator and first responders with descriptions of alarms and targets and the actions needed when the scheme is rendered unusable either during maintenance or because of a failure. The instructions will guide the operator on how to respond to component failures that partially impair the scheme or those failures that might disable entire scheme.

Regulatory agencies provide oversight of these schemes and require owners of these schemes to provide descriptions and operational information. NERC PRC-015 requires owners to provide description of schemes and the Study and Documentation Requirements section of this report proposes specific documentation requirements for inclusion in a revised standard. In addition to NERC, some Regional Entities also require SPS owners to provide the Region with additional information concerning the operations of the schemes. Some regional regulatory agencies also require the owners to verify that they have taken certain actions after a misoperation or a failure of these schemes.

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<sup>20</sup> Specifically,  $T_v$  is discussed in NERC Reliability Standard IRO-009-1, Requirement R2.

## Chapter 5 – Analysis of SPS Operations

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Operations of SPS provide an opportunity to assess their performance in actual operating power systems, as opposed to assessing the impact through a preconceived set of system studies. Analysis of SPS operations is presently addressed in PRC-012-0 and PRC-016-0.1, which establish requirements for Regional Reliability Organizations and SPS owners respectively. PRC-012-0 requires that each Regional Reliability Organization establish a regional definition of an SPS misoperation (R1.6), as well as requirements for analysis and documentation of corrective action plans for all SPS misoperations (R1.7). PRC-016-0.1 requires that SPS owners analyze their SPS operations and maintain a record of all misoperations in accordance with their regional SPS review procedure (R1) and that SPS owners take corrective actions to avoid future misoperations (R2).

PRC-012-0 is one of the standards identified in FERC Order No. 693 as a fill-in-the-blank standard and this standard therefore is not mandatory and enforceable. SAMS and SPCS have not identified any rationale for having regional definitions of an SPS misoperation or regional processes for analyzing SPS operations. Establishment of a continent-wide definition and review process will facilitate meaningful metrics for assessing the impact of SPS misoperations on bulk power system reliability. Rather than revising PRC-012-0 to assign responsibility for developing regional definitions and review processes to a user, owner, or operator of the bulk power system, this report recommends that one continent-wide definition and review process should be established through the NERC Reliability Standard Development Process, and that criteria be established for SPS owners to follow a continent-wide review process in place of the existing requirements in PRC-016-0.1.

### SPS Misoperation Definition

Establishing a definition of an SPS misoperation must account for the many different aspects affecting whether operation of an SPS achieves its desired effect on power system performance. In addition to aspects traditionally considered in assessing protection system misoperations such as failure to operate and unnecessary operation, analysis of an SPS operation also must consider whether the action was properly initiated and whether the initiated action achieved the desired power system performance. This report proposes that a tiered definition be used to assess which aspects of an SPS operation are reportable for metric purposes, which require analysis and reporting to the Reliability Coordinator and Planning Coordinator, and which require a corrective action plan. The following definition is recommended for an SPS misoperation.

#### *SPS Misoperation*

A SPS Misoperation includes any operation that exhibits one or more of the following attributes:

- a. Failure to Operate – Any failure of a SPS to perform its intended function within the designed time when system conditions intended to trigger the SPS occur.
- b. Unnecessary Operation – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s).
- c. Unintended System Response – Any unintended adverse system response to the SPS operation.
- d. Failure to Mitigate – Any failure of the SPS to mitigate the power system conditions for which it is intended.

The SPS review process should include requirements based on the SPS misoperation definition as follows:

- The SPS owner must provide analysis of all misoperations to its Reliability Coordinator and Planning Coordinator.
- The SPS owner must develop and implement a corrective action plan for all SPS misoperations.
- Reporting for reliability metric purposes should be limited to SPS misoperations that exhibit attributes (a) or (b) of the proposed definition, but should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

## SPS Operation Review Process

The review process should be included in a revised version of PRC-016 and PRC-012-0 should be retired upon approval of a continent-wide definition and revised PRC-016. The SPS operation review process should require that SPS owners analyze all SPS operations in sufficient detail to determine whether or not the response of the power system to the SPS operation is appropriate to meeting the purpose of the SPS. This requirement should be applied uniformly to all SPS types. The time required to review each SPS operation will vary with the complexity of the SPS.

The analysis of each operation should include:

- The power system conditions which triggered the SPS.
- A determination of whether or not the SPS responded as designed.
- An analysis of the power system response to the SPS operation.
- An analysis of the effectiveness of the SPS in mitigating power system issues it was designed to address. This analysis should identify whether or not those issues existed or were likely to occur at the time of the SPS operation.
- Any unintended or adverse power system response to the SPS operation.

For each SPS operation, the analysis should identify the power system conditions which existed at the time of the SPS operation. These conditions should be analyzed to determine whether or not the SPS operation was appropriate. This part of the analysis is to determine both whether or not the SPS operated as designed, and whether or not the conditions the SPS is intended to mitigate were present at the time of SPS operation.

Some SPS use a proxy to determine the possible existence of a system problem. For example, the opening of a generator outlet may cause an overload remote from the generator. An SPS could monitor the status of the outlet and run back generation to avoid the possible overload, rather than monitoring the loading on the potentially impacted element. The analysis should determine whether the SPS responded to the loss of outlet, and whether the overload actually would have occurred without SPS operation.

The analysis should also examine the response of the system to the SPS operation. This part of the analysis is to determine whether or not the SPS is effective in its intended mitigation, and if it has unforeseen adverse or unnecessary impacts on the power system.

As noted with the proposed definition above, the reporting requirements for each SPS misoperation should vary based on the attributes of the misoperation. The following discussion proposes reporting requirements and provides rationale for the type of SPS misoperation to which each should apply.

1. The SPS owner should be required to provide analysis of the misoperation to its Reliability Coordinator and Planning Coordinator for all SPS misoperations. The report should be provided to the Reliability Coordinator and the Planning Coordinator because such misoperations may require a reevaluation of the SPS under the review process proposed in the Study and Documentation Requirements section. The report should include the corrective action to assist the Reliability Coordinator and Planning Coordinator in confirming whether the SPS requires reevaluation.
2. The SPS owner should be required to develop and implement a corrective action plan for all SPS misoperations. Reporting details of the corrective action plan should be limited to purposes supporting reliability. As noted above, the report to the Reliability Coordinator and Planning Coordinator should include corrective actions. If an SPS must be removed from service or its operation is modified pending implementation of the corrective action plan, the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.
3. The SPS owner should be required to report for reliability metric purposes any SPS misoperation that involves a failure to operate or unnecessary operation. These attributes are analogous to protection system misoperations that must be reported and involve a failure of the SPS to operate per its installed design. The mechanism for

requiring reporting for reliability metric purposes should be similar to the process for reporting protection system misoperations under development in Project 2010-05.1: Protection Systems: Phase 1 (Misoperations).

4. The SPS owner should not be required to report or develop corrective action plans for other failures associated with an SPS that are not associated with an SPS operation or failure to operate, such as:
  - Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed;
  - Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and
  - Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions, if the system design requires automatic reset.

These types of failures can be corrected by the SPS owner without involving the Reliability Coordinator and the Planning Coordinator, and are analogous to a protection system owner identifying a failed power supply on a relay. If the failure has not resulted in a misoperation then reporting and corrective action plans are not required. It should be noted however, that operational requirements apply and if an SPS must be removed from service the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

## Chapter 6 – Recommendations

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### Definition

The existing SPS definition in the NERC glossary lacks clarity and specificity necessary for consistent identification and classification of SPS. The following strawman definition is proposed.

#### *Special Protection System*

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

- a) Underfrequency or undervoltage load shedding
- b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature
- c) Autoreclosing schemes
- d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers
- e) Schemes that prevent high line voltage by automatically switching the affected line
- f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open
- g) Out-of-step relaying
- h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty
- j) Automatic sequences that proceed when manually initiated solely by an operator
- k) Sub-synchronous resonance (SSR) protection schemes
- l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

## Classification

SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed:

- Type PS: planning – significant,
- Type PL: planning – limited,
- Type ES: extreme – significant, and
- Type EL: extreme – limited.

The planning classification applies to schemes designed to meet system performance requirements identified in the NERC Reliability Standards, while the extreme classification applies to schemes designed to limit the impact of two or more elements removed, an extreme event, or Cascading.

The significant classification applies to a scheme for which a failure to operate or inadvertent operation of the scheme can result in non-consequential load loss greater than or equal to 300 MW, aggregate resource loss (tripping or runback of generation or HVdc) greater than the largest Real Power resource within the interconnection, loss of synchronism between two portions of the system, or negatively damped oscillations. The limited classification applies to a scheme for which a failure to operate or inadvertent operation would not result in a significant impact.

## Applicability to Functional Model Entities

Three of the existing SPS-related reliability standards (PRC-012-0, PRC-013-0, and PRC-014-0) assign requirements to the Regional Reliability Organization. These standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693. This report recommends that requirements be reassigned to users, owners, and operators of the bulk power system in accordance with the NERC Functional Model. The following recommendations are included in the report:

- Review of new or modified SPS – assign to Reliability Coordinators and Planning Coordinators.
- SPS database maintenance – assign to Planning Coordinators; have Planning Coordinators submit databases to NERC for maintenance of a continent-wide database.
- Assessment of existing SPS – assign Planning Coordinators and Transmission Planners responsibility to include SPS assessments in annual transmission planning assessments; assign Reliability Coordinators responsibility to coordinate a periodic assessment of SPS design and coordination.

## Revisions to Reliability Standards

Figure 1 provides a high-level overview of recommendations related to the six PRC standards that apply to SPS. Recommendations include consolidating the six existing standards into three standards.

- Combine all requirements pertaining to review, assessment, and documentation of SPS (presently in PRC-012-0, PRC-013-0, PRC-014-0, and PRC-015-0) in one new standard, PRC-012-1. The requirement in PRC-012-0 for regional procedures for reviewing SPS misoperations is superseded by recommendations for revisions to PRC-016-0.1. The requirement in PRC-012-0 for regional maintenance and testing requirements is superseded by PRC-005-2.
- Requirements pertaining to analysis and reporting of SPS misoperations should be revised in a new standard, PRC-016-1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004.
- Requirements pertaining to maintenance and testing of SPS already have been translated to PRC-005-2 by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Additional detail is provided in Table 2 in Appendix C – Mapping of Requirements from Existing Standards. This table summarizes the recommendations for how each requirement in the existing six SPS-related standards should be mapped to revised standards. The more significant recommendations are summarized below.



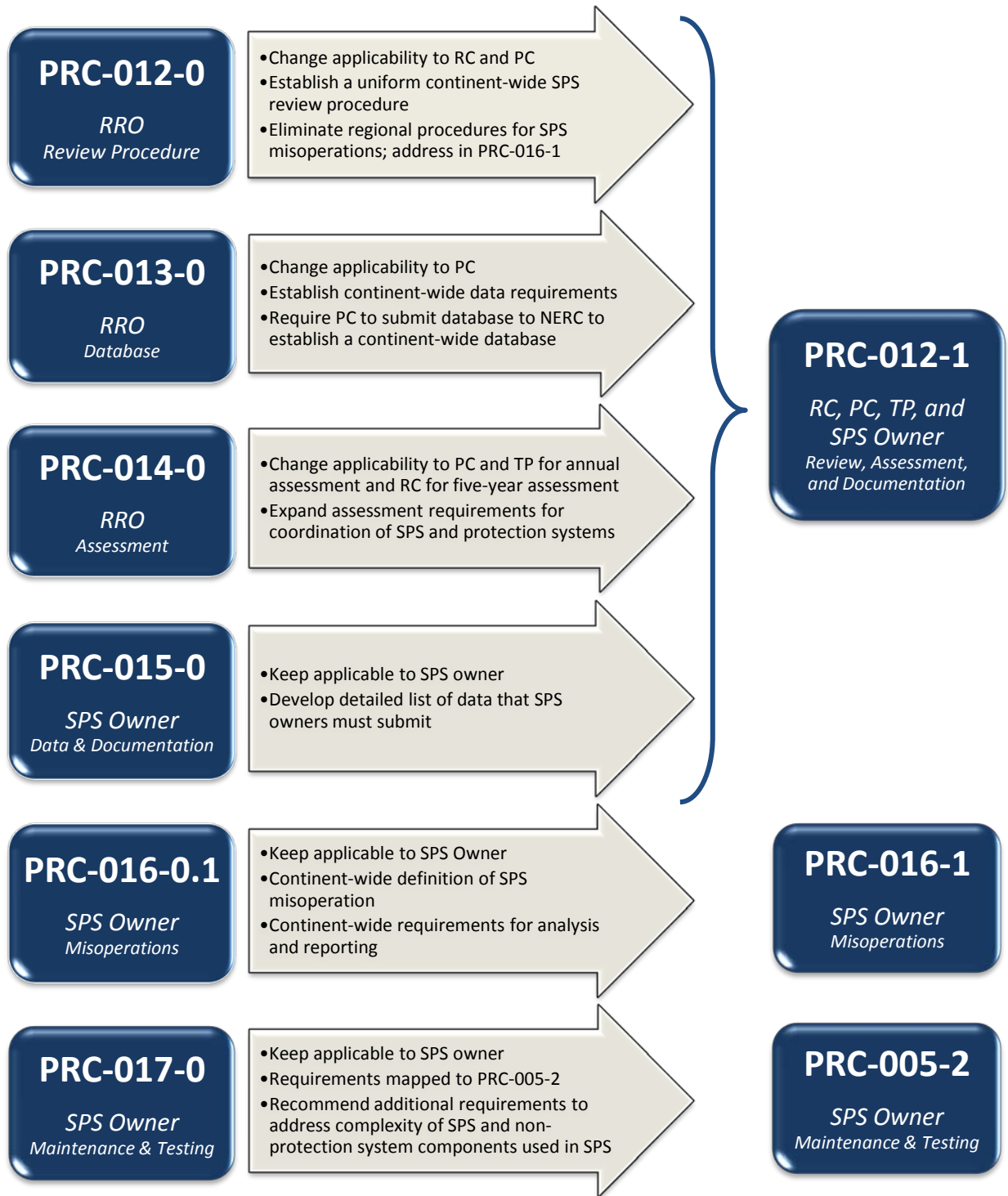


Figure 1 – Recommended Mapping of Existing PRC Standards

### **Standard PRC-012-1 – SPS Review, Assessment, and Documentation**

- SPS owners should be required to design Type PL and Type PS SPS so that a single SPS component failure does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, or TPL-003-0.
- Existing requirements for regional procedures for reviewing new or modified SPS should be replaced with a continent-wide procedure assigned to Reliability Coordinators and Planning Coordinators to assure a wide-area view of both planning and operational aspects of SPS.
- Annual transmission planning assessments should include an assessment by the Planning Coordinator and Transmission Planner to review the operation, coordination, and effectiveness of SPS, including the effect of correct operation, a failure to operate, and inadvertent operations.
- Periodic comprehensive assessments (every five years or less) of SPS should be performed by the Reliability Coordinator, with support as requested from other entities, to assess whether SPS are still necessary, serves their intended purpose, meet relevant design criteria, coordinate with other SPS, UFLS, UVLS, and protection systems, and do not have unintended adverse consequences on reliability.
- Detailed continent-wide requirements for data submittals should be established for SPS owners proposing new or modified SPS. Detailed recommendations are included in this report.
- Planning Coordinators should be assigned responsibility for maintaining databases containing all information submitted by SPS owners. Planning Coordinators should be required to submit their databases to NERC so that NERC can maintain and make available a continent-wide SPS database.

### **Standard PRC-016-1 – SPS Misoperations**

- PRC-016-1 should include a continent-wide definition of SPS misoperation based on the strawman definition proposed in this report.
- PRC-016-1 should include a continent-wide process for analysis of SPS operations and reporting SPS misoperations, including requirements for SPS owners to develop corrective action plans and provide analysis of SPS misoperations to Reliability Coordinators and Planning Coordinators.
- Reporting SPS operation and misoperation data for reliability metric purposes should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

### **Standard PRC-005-2 – Protection System Maintenance and Testing**

- Maintenance and testing requirements for SPS should be expanded in the NERC Reliability Standards to address the complexity of testing SPS and the maintenance of non-protection system components used in SPS. These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

### **Recommendations to Be Included in Other Standards**

This report discusses some aspects of SPS that are not addressed in the six SPS-related PRC standards. Recommendations should be incorporated in appropriate NERC Reliability Standards.

- SPS owners should be required to provide disturbance monitoring equipment to permit analysis of SPS performance following an event.
- Operating entities should be required to provide operators with documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.
- All SPS should be monitored by SCADA/EMS with real-time status communicated that minimally includes whether the scheme is in-service, out-of-service, and the current operational state of the scheme.
- One entity should be assigned responsibility for monitoring, coordination, and control of an SPS.

## Appendix A – Modeling and Simulation Considerations

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The addition of two stable control systems does not necessarily result in a stable composite control system; the same is true for SPS. Although the SPS may not be directly linked in their actions, their composite actions and effect on the electric system for commonly-sensed system conditions or perturbations can often behave as a single control system. Therefore, it is imperative that they be evaluated for their potential to interact with each other, particularly during a system disturbance. The composite interaction of multiple SPS, or of SPS with UFLS, UVLS, or other protection systems could result in system instability or cascading.

Because of the complexity of some schemes, modeling them in system simulation is currently performed most often by monitoring their trigger conditions and manually mimicking their intended actions such as changing system configuration, switching reactive devices, and adjusting or tripping generation. Such manual manipulations in powerflow and dynamics studies are only effective when studying a single SPS unless an iterative process is used. Even then, manual manipulation may not be effective and may not be possible in studying the simultaneous actions of multiple SPS that could potentially interact with each other. The difficulty is most significant when considering the potential interaction of parameter-based SPS, since interaction with event-based SPS would occur only if the initial event and SPS operation caused a second event to occur.

It is sometimes possible to simulate the behavior of a single SPS through simulation tools such as user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages. However, doing so for the myriad of SPS that may exist, even in a portion of an interconnection, is cumbersome. Furthermore, simulating multiple SPS in real-time operations tools (e.g., EMS) for real-time contingency analysis is extremely difficult and often requires new and innovative algorithm and software development. In addition, models used in real-time systems are often abridged or reduced equivalents and may not permit accurate representation of a particular SPS's functions. All of these issues are extremely problematic given the sheer number of SPS in North American interconnections.

To assure SPS will function in a coordinated fashion may require that they be modeled and studied from their design inception in the planning horizon, through pre-seasonal system studies that determine transfer capabilities, and in the operating horizon from day-ahead planning through the real-time contingency analysis that system operators depend on for guidance. Present analysis methods are limited by the capability of the software tools and management of the SPS, and in some cases protection system, data. The industry should put emphasis on future developments in these areas.

### General Considerations for Simulations

This section puts forth a number of factors, limitations, objectives, and overall guiding principles that a standard drafting team should consider in development of a new SPS standard with respect to the requirements for modeling and simulation, including data and process requirements necessary to support accurate and meaningful studies of SPS by Transmission Planners.

This report assumes that the modeling and simulation activities to be addressed are those performed for the planning horizon by Transmission Planning personnel. It is assumed that studies are performed using commercial off-the-shelf software packages and using databases derived from the interconnection-wide series of powerflow and dynamics cases. Studies using EMS based tools (e.g., study tools built into state estimators, real-time contingency analysis software, etc.) for real-time operations are not within the scope of this appendix.

It is important however, that the Transmission Planner share the results of planning horizon studies with operations personnel such that the impacts of SPS are effectively understood for the operating horizon also. This can be accomplished in a number of ways. Where operations support staff have similar study tools, sharing of the powerflow/dynamics cases, models, simulation scripts and similar data would enable them to evaluate SPS operation (or misoperation) for the operating horizon. Providing alarm or action limits for observable parameters (i.e., those that could be monitored in the operating environment) related to SPS operation would be another possibility. In this case, the parameters may be a direct indication or a proxy value that is indicative of the system condition of concern. Regardless of the process employed, the overriding consideration is that study results are adequately translated into actionable intelligence that is available to and understood by the system operator. While this is not intended to create a recommendation for a specific SPS standard

requirement, how this would ultimately be accomplished should be kept in mind as SPS standards are developed and implemented.

As a general rule, SPS are conceived by transmission planning engineers and implemented by protection and control engineers. To some extent, the engineers in these two groups are concerned with different aspects of SPS operation and use different terminology to describe SPS (and other system) functions. For example, a transmission planner may consider a protection system component failure to be a contingency while a protection engineer may consider this to be a design consideration. Transmission planning engineers conceive an SPS as a solution to system-level problems. Their focus is on the “big picture” functional operation of the SPS for specific system level conditions. Protection and control engineers implement an SPS via detailed design using various sensors, relays, etc. Their focus is on efficiently implementing the functional requirements as they understand them to be. It is imperative that the planning engineers effectively communicate the requirements of the SPS to protection engineers and monitor the design and implementation of the scheme to ensure that the SPS is implemented and functions as prescribed by the planner.

The planning and protection engineers should also consult with the operations personnel to ensure that possible system-level events which might result in unintended SPS operation are considered. Involving operations personnel at each stage of the design process will help ensure that the range of operating conditions likely to be encountered in the real world (including outages), as well as practical operating considerations, are also adequately considered in the SPS design and implementation.

An explicit requirement should exist to represent the salient features of SPS operation in a form that can be readily shared with, understood by, and used in simulations by other Transmission Planners. Simulation of SPS in powerflow or dynamic studies may involve a combination of using standard relay models, various monitoring features, and scripts or program code to adequately simulate the functioning of the SPS. These may include user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages (either executed during solution-run time or as user-written dynamic models), etc. Transmission Planners generally have their own individual preferences as to how to reflect these functions when performing simulations. Additionally, different Transmission Planning organizations have different levels of expertise in developing scenarios to reflect actual system operation and performing simulations based on those scenarios. Therefore, it is important that the modeling information to be used by other Transmission Planning engineers as input (including run scripts) in simulations be simple, understandable and well documented. Any scripts or models provided need to be “open source” in nature and well-documented to enable independent verification. The use of user models, FORTRAN object code, compiled scripts, and similar which make it difficult for the receiving Transmission Planner to review and understand how the SPS model functions must be avoided.

In addition to providing the relay models, program code/script, and similar input as part of the database, a summary document should be provided explaining the SPS. The information shared must include a summary and guidance document which includes the following, as applicable.

- An overview explanation of the basic functioning of the SPS, describing when and how it operates
- A listing of the setpoints applicable to the SPS (e.g., relay trip settings, etc.)
- A summary overview of how the SPS is being simulated via relay models, simulation scripts that may be provided
- Specific bus numbers, branch identifiers, machine identifiers, etc. should be referenced to help the Transmission Planner receiving this information understand how the SPS is being simulated

SPS modeling information should be readily available as part of the interconnection-wide modeling processes, but not an integral part of an interconnection-wide case year database. Specific recommendations are included in the chapter on study and documentation requirements.

Because of the special nature of SPS, it is not practical or even possible to include them in the interconnection-wide load flow and/or dynamic database case years in the classic sense (e.g., such as one would include a generator or FACTS device model). Additionally, it is simply not necessary to model all SPS for all simulations. The reality is that an SPS in the Northeast will likely have very little impact on the results of simulations focused on the Southeast. Therefore, including all SPS in all simulations places an unreasonable burden on Transmission Planners. However, due consideration should be given to the

interaction of a given SPS with other SPS. Note that geographical distance alone may not be sufficient justification not to consider the interaction of several SPS.

However, it is important that information about all SPS be available for use, as deemed appropriate by the Transmission Planners whose systems may be affected by the SPS operation (or misoperation). It is also important the relevant parameter-based SPS be modeled concurrently in simulations to appropriately evaluate potential interactions among the SPS.

Therefore, the data management process for providing SPS information for simulations purposes should include the following considerations.

- Sufficiently detailed SPS information and documentation as described above can be managed as part of the interconnection-wide powerflow and dynamic case creation process.
- Providing the models and simulation scripts alone is not sufficient. A functional description to assist the Transmission Planner in understanding how these modeling/simulation elements work to emulate the SPS function is necessary in order for the Transmission Planner to properly simulate and interpret the results of simulations involving the SPS.
- The SPS information may reside separately from the interconnection-wide powerflow and dynamic cases, but a clear association to each case must be evident.
- Each Transmission Planner will be able to select the SPS that are relevant to the simulation they are performing. Engineering judgment, with a documented reason, for excluding SPS from simulations is acceptable.
- Where included, the impact of multiple SPS and their interaction should be reasonably accounted for in the simulation activities.

It is envisioned that Transmission Planners will generally include only those SPS that, in their judgment, are relative to the simulations being performed and/or could potentially interact with other SPS being included in these simulations. However, it would be prudent to have some big picture check for unintended SPS interaction. Therefore, a joint, interconnection-wide study or assessment should be periodically performed to evaluate potential interactions among SPS across the entire interconnection. Such a study or assessment should include modeling and simulation of all of the SPS throughout the interconnection. A periodicity of five years for this joint study is suggested as an appropriate time frame.

## Use of SPS Simulations in Transmission Planning Studies

SPS are used as alternatives to transmission infrastructure to support reliable system operation for identified concerns. As such, these schemes must be analyzed in transmission planning analyses just as any other transmission system addition would be, with a focus on:

- Operation as expected for the design case of concern
- Understanding the potential for operation beyond the original design intent
- Determining if there is a potential for failure to operate to rectify the design case of concern.

In system planning, the types of studies which are typically performed to determine system performance are powerflow and dynamic simulations and analyses. SPS need to be modeled in both of these types of studies.

Powerflow (i.e., steady-state) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS monitoring and consequent actions with scripting and programming automatically called during powerflow processing
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- Contingencies are included in the analysis with and without the SPS actuated
- Monitoring of system performance to determine if system conditions would actuate an SPS

- The monitoring occurs for all contingencies examined
- Any result indicating potential actuation of an SPS is rerun with the SPS actuated

Dynamic (i.e., stability) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS in the dynamic simulation with a model that includes the monitoring and consequent actions during the dynamic simulations
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- The dynamic/stability contingencies are included in the analysis with and without the SPS actuated
- Monitoring of SPS trigger elements (voltage, current, flow and/or frequency on system elements or element status) to determine if actuation of an SPS would have actuated
  - Rerun the simulation with the SPS actuated if the monitored results indicate potential actuation of the SPS

The SPS modeling techniques used in system planning should be based upon modeling information provided by the SPS owner which clearly describes what the SPS senses and the consequent actions taken when its triggering needs are met.

The need for accurate modeling information can be demonstrated with an example. In the example, two SPS exist in an area. One SPS trips a large generating plant for loss of a transmission circuit due to first swing stability concerns. This SPS acts within cycles of the initiating line loss. The second SPS inserts a series reactor into a transmission circuit to limit flow and eliminate an overload on the circuit. The second SPS acts within seconds (5 seconds for this example) of the overload condition occurring.

Steady state studies of the area where these SPS exist would examine the representative cases (sets of system conditions) and contingency sets for the study in question. If the power flow software allowed, a post-solution program could be run to test if the actuating circumstances for each SPS were met; if so, the contingent solution would be rerun and tested again for any other SPS which would actuate. If the power flow software did not have this flexibility, the engineer could include an SPS actuation for those contingencies expected to trigger the SPS and run that expanded contingency list; the results could be examined with attention paid to the loading for the circuit protected by the second SPS. Any contingencies which caused an overload on the triggering circuit could be rerun with the SPS actuated.

Since both SPS act within the dynamic simulation timeframe, the SPS should be modeled or monitored in stability simulations. Dynamic models could exist for both SPS. Should the flow on the SPS-triggering line exceed the flow actuation setpoint for the required time duration, the dynamic simulation would capture the impact of the reactor insertion and the SPS actuation. If the SPS were not explicitly modeled, their trigger values could be monitored (i.e., the status or flow on the line for the first SPS and the flow on the potentially overloaded circuit for the second SPS). The monitored data channels would be examined after each simulation to determine if the simulation needed to be rerun while modeling the appropriate SPS actions.

The goal for modeling SPS in studies is to confirm that they will operate to correct the intended system concerns as necessary to preserve acceptable system performance. In addition, the analyses provide understanding for system planning and operations on when and how the use of the SPS may change over time. This information may be critical for system operations staff to maintain reliable system operation.

## Appendix B – Operational Considerations

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This information is a high level list of important issues and concerns if performing SPS analyses in real-time operations.

### Real-time SPS Evaluation

Current system conditions must be identified before evaluating whether an SPS would perform its function and achieve its desired outcome. Results of security analysis should be required to indicate whether an SPS should be armed (if armed manually) and whether an SPS will operate for a given contingency. Security analysis should model operation of the SPS in addition to the initiating contingency when the SPS is armed.

SPS evaluation often cannot be done with SCADA input alone. Some non-SCADA input may be needed; for example, limits from off-line studies are converted into inputs available in the Energy Management System (EMS). The inputs that support SPS evaluation and operation need to be codified in operating guides and presented on operator displays for ease of use and operation. Custom code and displays are generally required to aggregate all needed information for usage by engineers and operators in real time.

The impact of SPS operation on facilities external to the SPS owner/operator needs to be jointly considered and communicated to external entities and appropriately accounted for in EMS. Furthermore, the effects of external contingencies on the SPS triggers should be accounted for within EMS and known to operators.

SPS evaluation typically involves the testing of a limited set of relevant contingencies, requiring the use Real-Time Contingency Analysis (RTCA). In some cases, a dc solution to identify thermal issues is adequate; in other cases, a full ac solution is required (e.g., where triggers are voltage dependent).

Some EMS are not robust enough to compute ac solutions in EMS/RTCA. Depending on the classification of an SPS (e.g., significant), an EMS/RTCA with such limited capability would be insufficient to evaluate the impact of the SPS. In such cases it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

If the EMS/RTCA does not reach a solved state, then the SPS cannot be evaluated. For example, some EMS/RTCA will fail to solve or fail to converge upon the creation of islands in the model. In these cases, SPS modeling may require custom software solutions.

### Multiple Decision-Making Capability

When evaluating SPS in EMS/RTCA, intermediate steps must be modeled and intermediate states must be evaluated. It should be assumed that an SPS may suffer a full or partial failure and that system conditions will change as the SPS operates. Adverse conditions may arise during intermediate steps that lead to undesired outcomes or put the system into an unplanned operating state.

The post-contingency, pre-SPS-operation state must be known to assess system conditions before the SPS action can be evaluated. For example, the loss of a large nuclear station automatically activates a large emergency core cooling load. This new system state would require a re-solution to check post-contingent node voltage (i.e., with the load connected) before consideration of SPS activation and results can occur. This requires that several stages and intermediate actions be modeled in the evolution of the final system topology to ensure that the system can reach the desired end-state.

### Information Management

Each SPS may have its own set of arming and activation triggers. Examples include equipment status, line loading and voltage. These triggers may be complex, and could affect the alarming capability required of EMS.

Changes to EMS models may require long lead times before an SPS can be implemented; for example, changes to models often require pushing through multiple staged software environments. Entities should use software designs that are flexible to accommodate timely changes to SPS models that might not be tied to the network model database release schedule. When implementing an SPS before the EMS model can be updated, it is necessary to establish other means, such as

supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

## **Modeling Simplicity and Usability**

Complex SPS schemes require due diligence to maintain and support. Entities should be required to develop and document an efficient approach to SPS control. An entity's strategy should allow for concurrent and/or consecutive SPS actions.



## Appendix C – Mapping of Requirements from Existing Standards

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal   | Comments   |
|-------------------|---|--|--|
| PRC-012-0         | R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: | PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.   | See Review and Approval of New or Modified SPS on pp. 16-17. |
| PRC-012-0         | R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.  | PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.   | See Review and Approval of New or Modified SPS on pp. 16-17. |
| PRC-012-0         | R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.  | PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system. | See Data Submittals by Entities that Own SPS on pp. 18-19.   |
| PRC-012-0         | R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.  | PRC-012-1 should require that all Type PS and PL SPS are designed so system performance requirements are met in the event of a single component failure within the SPS.                                      | See SPS Single Component Failure Requirements on p. 14-15    |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal  | Comments   |
|-------------------|---|---|--|
| PRC-012-0         | R1.4. Requirements to demonstrate that the inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0. | PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation. | See Review and Approval of New or Modified SPS on p. 16.   |
| PRC-012-0         | R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.   | PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation. | See Review and Approval of New or Modified SPS on p. 16.   |
| PRC-012-0         | R1.6. Regional Reliability Organization definition of misoperation.   | A continent-wide definition of an SPS misoperation should be established.   | See SPS Misoperation Definition on p. 22.  |
| PRC-012-0         | R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.   | Do not carry forward to revised standards.  | The need for this requirement is eliminated by establishing continent-wide requirements in PRC-016-1. See SPS Operation Review Process on pp. 23-24.                         |
| PRC-012-0         | R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization’s review procedure and the process for Regional Reliability Organization approval of the procedure.                         | Do not carry forward to revised standards.  | The need for this requirement is eliminated by establishing a continent-wide review procedure within PRC-012-1. See Review and Approval of New or Modified SPS on pp. 16-17. |
| PRC-012-0         | R1.9. Determination, as appropriate, of maintenance and testing requirements.   | Do not carry forward to revised standards.  | The need for this requirement is eliminated by establishing continent-wide maintenance and testing requirements within PRC-005-2.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal  | Comments  |
|-------------------|---|---|---|
| PRC-012-0         | R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).                                       | Do not carry forward to revised standards.  | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-013-0         | R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information: | PRC-012-1 should require that each Planning Coordinator maintain a database, and provide the database to NERC for the purpose of maintaining a continent-wide database. | See SPS Database on p. 19.  |
| PRC-013-0         | R1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed,   | This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.     | See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.  |
| PRC-013-0         | R1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and   | This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.     | See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.  |
| PRC-013-0         | R1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS.  | This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.     | See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal   | Comments  |
|-------------------|---|--|---|
| PRC-013-0         | R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).  | Do not carry forward to revised standards.   | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-014-0         | R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.  | PRC-012-1 should require the Planning Coordinator and Transmission Planner to assess SPS in annual transmission planning assessments and require the Reliability Coordinator to conduct a periodic review every five years, or sooner if significant changes are made to the system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems. | See Periodic Comprehensive Assessments of SPS Coordination on p. 17.  |
| PRC-014-0         | R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days). | Do not carry forward to revised standards.   | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-014-0         | R3. The documentation of the Regional Reliability Organization’s SPS assessment shall include the following elements:   | PRC-012-1 should require the Reliability Coordinator to document its periodic assessments. The documentation should include the same elements required in a study supporting approval of a new or modified SPS.  | See Review and Approval of New or Modified SPS on pp. 16-17 and Assessment of Existing SPS on p. 17.  |
| PRC-014-0         | R3.1. Identification of group conducting the assessment and the date the assessment was performed.  | This list of elements includes: <ul style="list-style-type: none"> <li>Entity conducting the study</li> <li>Study completion date</li> </ul>   | See Review and Approval of New or Modified SPS on pp. 16-17.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal   | Comments   |
|-------------------|---|--|--|
| PRC-014-0         | R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed. | This list of elements includes: <ul style="list-style-type: none"> <li>• Study years</li> <li>• System conditions</li> <li>• Contingencies analyzed</li> <li>• Study completion date</li> </ul>  | See Review and Approval of New or Modified SPS on pp. 16-17.         |
| PRC-014-0         | R3.3. Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.  | PRC-012-1 should require the Planning Coordinator and Transmission Planner document and submit any issues identified in the annual assessment to the Reliability Coordinator.<br>PRC-012-1 should require the Reliability Coordinator to document and submit any issues identified in the periodic assessment to the SPS owner.  | See Assessment of Existing SPS on p. 17.                             |
| PRC-014-0         | R3.4. Discussion of any coordination problems found between a SPS and other protection and control systems.   | PRC-012-1 should require the Reliability Coordinator to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets performance criteria, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.  | See Periodic Comprehensive Assessments of SPS Coordination on p. 17. |
| PRC-014-0         | R3.5. Provide corrective action plans for non-compliant SPSs.   | PRC-012-1 should require that if issues are identified in an annual or periodic assessment, the Reliability Coordinator and Planning Coordinator determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in service until a corrective action plan is implemented.<br>If a corrective action plan is required, PRC-012-1 should require the SPS owner to submit an application for a new or modified SPS. | See Assessment of Existing SPS on p. 17.                             |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement   | Proposal  | Comments  |
|-------------------|---|---|---|
| PRC-015-0         | R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.   | PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.  | See Data Submittals by Entities that Own SPS on pp. 18-19.  |
| PRC-015-0         | R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.   | Do not carry forward to revised standards. PRC-012-1 should have a requirement for the SPS owner to file an application for approval of an SPS, which assures that the SPS is reviewed in accordance with the continent-wide review procedure prior to being placed in service. | See Review and Approval of New or Modified SPS on pp. 16-17.  |
| PRC-015-0         | R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days). | Do not carry forward to revised standards.  | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-016-0.1       | R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.  | PRC-016-1 should establish a continent-wide process for analyzing and reporting SPS misoperations.  | See SPS Operation Review Process on pp. 23-24.  |

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard       | Requirement  | Proposal  | Comments  |
|-------------------------|--|---|---|
| PRC-016-0.1             | R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.   | PRC-016-1 should establish a requirement that the SPS owner should be required to develop and implement a corrective action plan for SPS misoperations. | See SPS Operation Review Process on pp. 23-24.  |
| PRC-016-0.1             | R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days). | Do not carry forward to revised standards.  | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |
| PRC-017-0 <sup>21</sup> | R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1.  |
| PRC-017-0               | R1.1. SPS identification shall include but is not limited to:  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Tables 1-1 – 1-5, and Table 2.   |
| PRC-017-0               | R1.1.1. Relays.  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-1.   |
| PRC-017-0               | R1.1.2. Instrument transformers.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-3.   |
| PRC-017-0               | R1.1.3. Communications systems, where appropriate.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-2.   |

<sup>21</sup> Mapping for requirements in PRC-017-0 are adapted from the mapping document developed by the Project 2007-17 Protection System Maintenance & Testing drafting team.

**Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards**

| Existing Standard | Requirement  | Proposal  | Comments  |
|-------------------|--|---|---|
| PRC-017-0         | R1.1.4. Batteries.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, Table 1-4.   |
| PRC-017-0         | R1.2. Documentation of maintenance and testing intervals and their basis.  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1 and R2.   |
| PRC-017-0         | R1.3. Summary of testing procedure.  | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1, Tables 1-1 – 1-5, and Table 2.   |
| PRC-017-0         | R1.4. Schedule for system testing.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1 and R2.   |
| PRC-017-0         | R1.5. Schedule for system maintenance.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R1 and R2  |
| PRC-017-0         | R1.6. Date last tested/maintained.   | Addressed by Project 2007-17, Protection System Maintenance and Testing   | See PRC-005-2, R3 and associated Measures, R4 and associated Measure, and Data Retention.   |
| PRC-017-0         | R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days). | Addressed by Project 2007-17, Protection System Maintenance and Testing; this requirement is not carried forward to the revised standard. | Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information. |



# Appendix D – Standards Committee Request for Research; January 9, 2011

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## Request for Research

Project 2010-05.2

Phase 2 of Protection Systems: SPS and RAS

### Introduction

NERC's Standards Committee has tentatively identified this project for initiation in late 2012. Prior to then, there is a need for additional research and scoping of the project to determine:

- What is the problem that this project will try to solve?
- Is the development of a standard the appropriate manner to solve that problem, or should alternative approaches be used?
- If a standard is appropriate, what is the recommended solution to the problem?

Results based standards projects use the approach of defining the needs, goals, and objectives for the project. For this project, we would like your assistance in this effort. Below is a draft problem statement for your consideration.

### *Need (Problem)*

**Special Protection Systems (SPS) and Remedial Action Schemes (RAS) can misoperate and negatively impact the reliability of the BES.**

Does the need above correctly document the concern described in the attached draft SAR?

Do you agree that this is a problem that needs to be addressed?

Is a standard the appropriate vehicle to address this problem, or should an alternative approach be used? If an alternative, is recommended, what would that alternative be?

If development of a standard is appropriate, then please consider the following Goal

### *Goal (Solution)*

**Require the analysis, reporting, and correction of Misoperations of SPS and RAS.**

### Request

Please provide the Standards Committee with the following information:

- An updated Need/Problem (or a statement of concurrence with the draft presented here)
- A statement indicating whether or not you believe this problem is one which needs to be addressed
- If you agree the problem needs to be addressed, a suggestion for how to address the problem
- If you suggest a standard be developed to address the problem, then please provide
  - An updated goal (or a statement of concurrence with the draft presented here)
  - A set of objectives in support of that goal
  - If you have any suggested changes to the attached draft SAR, please propose them
  - If you have specific recommendations for requirements language or additional information, please include them

Thank you in advance for your assistance.

## Appendix E – Scope of Work Approved by the Planning Committee; June 8, 2011

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### Assessment of Special Protection System Standards and Regional Practices

#### **Proposal:**

The SPCS proposes to conduct an assessment of the SPS-related PRC standards and definition of SPS, conduct an assessment of existing regional practices summarizing commonality and differences, and to document its findings in a report to the Planning Committee that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a Compliance Application Notice (CAN) to address part of this issue until a revised definition and standard(s) are developed. The SPCS further proposes this activity should be a joint effort with the Transmission Issues Subcommittee (TIS).

#### **Rationale:**

- The SPCS scope calls for providing subject matter expertise for NERC Standards related to protection systems and controls, and the SPCS work plan includes an assignment to review all existing PRC-series Reliability Standards, to advise the Planning Committee of its assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.
- The SPCS has reviewed all PRC standards except the group of SPS standards. The SPCS had started assessment of these standards, but the assessment was deferred due to other priority work such as the Power Plant and Transmission System Protection Coordination technical reference document.
- The SPCS has reviewed its work plan and determined that this is the next logical project for the SPCS. Work on the Transmission System Phase Backup Protection reliability guideline is wrapping up at this time and the SPCS can make the SPS review one of two priority activities for this year (the other is the document addressing operation of protection systems in response to power swings).
- The SPCS believes that a thorough review of SPS-related PRC standards would benefit from the expertise of TIS and the SPCS recommends a joint SPCS/TIS effort coordinated by the SPCS. This proposal has been reviewed with and is supported by TIS.
- The SPCS proposes to conduct an assessment of the standards and definition of SPS, and conduct an assessment of existing regional practices summarizing commonality and differences among the various regional practices.
- The SPCS believes that differences among regional practices must be resolved through a formal process; a consensus opinion of what constitutes an SPCS would lack standing unless it is vetted through a stakeholder process. The SPCS proposes to document its findings in a report that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a CAN to address part of this issue until a revised standard(s) is developed.
- The scope of work for such a review is significant and direction should come through the NERC Planning Committee as the body to which SPCS and TIS report.
- The SPCS believes that an appropriate time frame for completing this report would be to submit a draft to the Planning Committee at its March 2012 meeting. The SPCS and TIS believe this schedule is appropriate to support a thorough review.

Approved by the NERC Planning Committee  
June 8, 2011

# Appendix F – System Analysis and Modeling Subcommittee Roster

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# Appendix G – System Protection and Control Subcommittee Roster

---

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## Appendix H – Additional Contributors

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GE Energy Management

## Appendix I – Revision History

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| Revision History |                |   |
|------------------|----------------|---|
| Version          | Date           | Modification(s)   |
| 0                | March 5, 2013  | Initial Document  |
| 0.1              | April 18, 2013 | Appendix A – Correction to remove trade names and replace with generic language in the section, General Considerations for Simulation |

# Project 2008-02 Undervoltage Load Shedding

Recommended Coordination Plan | March 14, 2014

## Background

Project 2008-02 Undervoltage Load Shedding (“UVLS Project”) proposes to consolidate and retire PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1 to create PRC-010-1 – Undervoltage Load Shedding. During development, the drafting team identified the following necessary corresponding changes to meet the design of PRC-010-1:

- 1) Modify PRC-004-3 – Protection System Misoperation Identification and Correction, which excludes UVLS, to include certain types of UVLS programs as part of its applicable facilities.
- 2) Retire three requirements in EOP-003-2 – Load Shedding Plans whose required performance is reflected in proposed PRC-010-1.
- 3) Modify the current NERC Glossary definition of the term Special Protection System (SPS), which excludes UVLS, to include a subset of UVLS programs that are more appropriately categorized as SPSs and covered by SPS-related standards.

In order to make the necessary changes, the UVLS Project needs to coordinate with ongoing development work in three active NERC standard development projects as follows:

- Project 2010-05.1 Protection Systems: Phase 1 (Misoperations) (“Misoperations Project”)
- Project 2009-03 Emergency Operations (“EOP Project”)
- Project 2010-05.2 Protection Systems: Phase 2 (Special Protection Systems) (“SPS Project”)

## Current Recommended Plan

As a result, NERC has identified a preferred project plan to coordinate the above-mentioned projects to properly align legacy standard retirements and revised standard implementations due to the differences in each project's timing. In short, the revised SPS definition, the UVLS Project, and the EOP Project will be presented simultaneously to industry, the NERC Board of Trustees, and applicable regulatory authorities. An illustrative diagram of this coordination appears on the next page. This plan is subject to change as necessary.

- 1) The UVLS Project will address the conforming changes needed to PRC-004 after PRC-004-3 is complete. How and when this will occur depends on when PRC-004-3 obtains approval from the ballot body and is adopted by the NERC Board of Trustees.
- 2) The EOP and UVLS Projects will progress simultaneously and coordinate necessary changes.
- 3) The SPS Project is proposing to revise the definition of SPS in advance of revising the SPS standards. The UVLS Project will progress simultaneously with the SPS definition revision in order to properly transfer certain aspects of the legacy UVLS standards into coverage under the SPS standards.

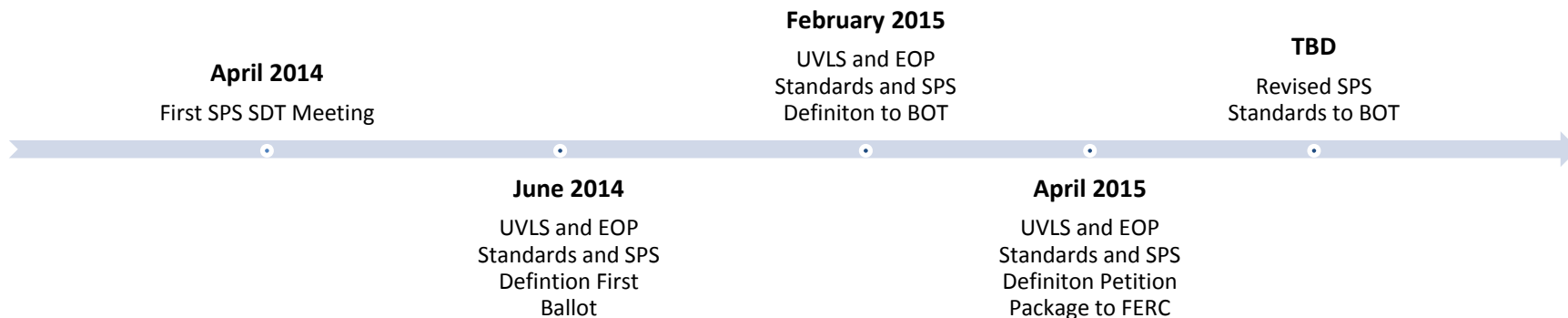
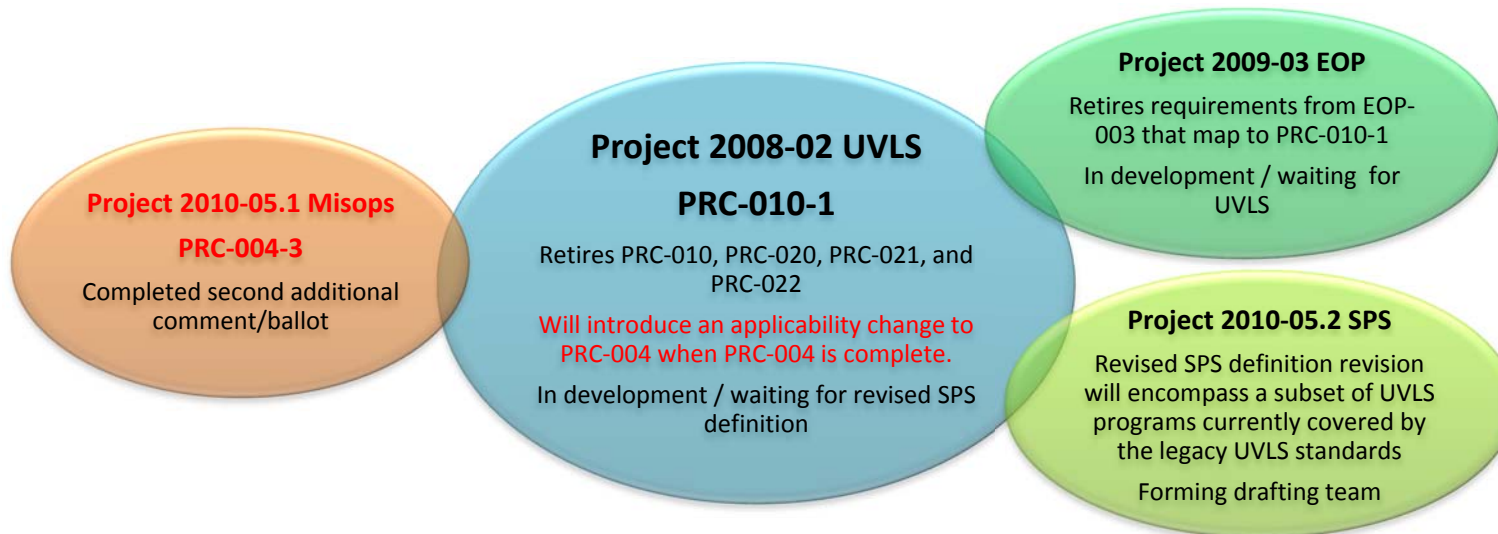
## Impacts

As a result of the necessary coordination above, the UVLS Project and the EOP Project are now timed by the schedule for the SPS Project, which is targeting the approval of the revised SPS definition at the February 2015 NERC Board of Trustees meeting.

## Additional Considerations

Of note, Project 2007-17.3 Protection System Maintenance and Testing: Phase 3 (Sudden Pressure Relays) is beginning development on version 4 of PRC-005, which may consider use of a new defined term introduced by the UVLS Project. Therefore, this project may also coordinate with the UVLS Project as needed.





## Standards Announcement

### Project 2010-05.2 Phase 2 of Protection Systems (Special Protection Systems) Standard Authorization Request

Informal Comment Period Now Open through March 19, 2014

#### [Now Available](#)

A 30-day comment period for the **Phase 2 of Protection Systems – Special Protection Systems** Standard Authorization Request is open through **8 p.m. Eastern on Wednesday, March 19, 2014.**

#### Instructions for Commenting

The comment period is open through **8 p.m. Eastern on Wednesday, March 19, 2014.** Please use the [electronic form](#) to submit comments on the SAR. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

For information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Wendy Muller](#),  
Standards Development Administrator, or at 404-446-2560.*

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**Individual or group. (20 Responses)**  
**Name (11 Responses)**  
**Organization (11 Responses)**  
**Group Name (9 Responses)**  
**Lead Contact (9 Responses)**  
**Question 1 (20 Responses)**  
**Question 1 Comments (20 Responses)**  
**Question 2 (18 Responses)**  
**Question 2 Comments (20 Responses)**  
**Question 3 (0 Responses)**  
**Question 3 Comments (20 Responses)**

|   |
|---|
|   |
| Group   |
| Northeast Power Coordinating Council  |
| Guy Zito  |
| Yes   |
| The annual assessment of SPS in transmission planning studies should be addressed within Transmission Planning (TPL) standards. We recommend that Transmission Planning requirements not be included in Protection and Control (PRC) standards.   |
| No  |
|   |
|   |
| Individual  |
| Anthony Jablonski   |
| ReliabilityFirst  |
| Yes   |
| ReliabilityFirst agrees with the scope of the SAR and believes these revised standards will enhance reliability. Specifically a modified SPS definition will increase clarity and removal of the RRO as the applicable entity from certain standards will remove the "fill-in the blank" aspects and correctly make them enforceable on users, owners and operators of the BES. |
|   |
|   |
| Group   |
| MRO NERC Standards Review Forum   |
| Joseph DePoorter  |
| Yes   |
| The current draft of the SAR scope includes PRC-017 to avoid any gaps or overlap between PRC-017 and the proposed SPS standard. Since the PRC-017 standard is scheduled to be   |

retired with the effective date of PRC-005-2, which is April 1, 2014, PRC-005-2 already includes in its scope the maintenance and testing requirements of the Protection System elements of a SPS. Therefore there is no gap, and addressing of PRC-017 in the SPS standard creates overlap and potential double jeopardy (between PRC-005-2 and the SPS standard). It is recommended that the maintenance and testing requirements of all of the elements of the SPS be in the same standard and not split the requirements for the testing of parts of the SPS into two standards. Since the specific requirements for the testing of the "Protection System components" of a SPS are already in PRC-005, it seems to make more sense to simply make PRC-005 apply to "all" components (parts) of a SPS, rather than repeat the specific requirements for the testing in a second standard. While the NSRF understands that SPS misoperations were not addressed in the recent PRC-004 revision, the NSRF believes that SPS misoperations can be addressed under PRC-004-3 without any further significant modifications. Once the definition of a SPS is clearly determined (part of this project), the analysis of any operation (or lack of operation) of the scheme does not need to be treated any differently than other Protection System analysis and correct-operation determination. It is recommended that the evaluation of proper/improper operation of a SPS be included in PRC-004 rather than in a second Misoperation standard, PRC-016. Once the definition of a SPS is well defined, it should be no more or less difficult to determine if it operated correctly than any other protection scheme. The time frames for review, possible involvement of multiple parties, and Corrective Action Plans aspects apply directly to SPSs just as they do to ordinary Protection System schemes. The SAR scope should be expanded to include more definition of the term, "functional modification." There will continue to be uncertainty and inconsistency regarding which SPS changes are a "functional modification" until specific criteria and examples are developed. For instance, the criteria and examples should be able to address the treatment of such changes as a direct replacement of a failed SPS component failure (e.g. SEL-321 relay for SEL-321 relay), upgrading a SEL-321 relay with a SEL-421 relay with the same logic, and using a different logic to accomplish the same system result.

No

The NRSF has concerns that the proposed SPS definition in the technical paper remains broad, lacks sufficient clarity and the specificity necessary for consistent identification / classification of SPS systems across all eight regions. While the SPCS effort is commendable, the definition remains overly broad and will continue to bring in protection systems that don't affect the security of the BES. This is evidenced by the long list of identified exclusions. The drafting team cannot identify and exclude all possible protection schemes that respond to non-fault conditions and entities will continue to identify more systems that need to be excluded as there are many reasons to install specific protection systems. The MRO NSRF suggests that the SAR allow room for the drafting team to consider enhancements other than what is proposed in the SPCS technical paper. Perhaps a hybrid definition / screening process followed by a specific BES system instability analysis are needed to 1) clearly communicate the SPS definition intentions, and 2) identifying only BES

protection systems that are “Special” because they have a regional impact on BES security. An example is the difference between a reverse power relay that trips a backfed 100kV and greater BES bus (which should not be a special protection system), versus the SONGS scheme that helped trigger the southwest power outage (which should be special due to its security impact on the BES). The hybrid definition / screening process could start with an English SPS definition similar to what was proposed by the SPCS allowing entities to quickly screen protection systems for potential inclusions and exclusions similar to the BES definition. This could be followed by a BES security impact analysis which would screen for BES transmission instability, uncontrolled separation, and cascading using known and understood power stability program stability analyses similar to the TPL standards. This would provide repeatable concrete and measurable results that would clearly identify protection schemes that had a BES security impact. Concrete and measurable criteria could be specified using understood industry practices and IEEE papers or standards for identifying when BES security was impacted through regional undamped and poorly damped power system oscillations.

Individual

Jonathan Meyer

Idaho Power Co.

No

No

Individual

Oliver Burke

Entergy Services, Inc.

No

No

The centralized UVLS program should be considered as part of SPS.

Individual

Thomas Foltz

American Electric Power

Yes

The SAR proposes that PRC-017-0 be retired or revised, however this standard is already approved to be retired under PRC-005-2.

No

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| We are hopeful that the establishment of SPS “types”, as detailed in the SPCS technical report, may eliminate the need for regional variances.  |
| We are encouraged by NERC’s willingness to pursue revision of the definition of Special Protection Systems and impacted standards.  |
| Group   |
| PPL NERC Registered Affiliates  |
| Brent Ingebrigtsen  |
| No  |
| Comments: These comments are submitted on behalf of the following PPL NERC Registered Affiliates (“PPL”): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.  |
| No  |
|   |
| None  |
| Group   |
| Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing  |
| Wayne Johnson   |
| Yes   |
| The current draft of the SAR scope includes PRC-017-0. This standard is scheduled to be retired with the effective date of PRC-005-2, which is 01 Apr 2014. PRC-005-2 already includes in its scope the maintenance and testing requirements of the Protection System elements of a SPS. It is recommended that the maintenance and testing requirements of all of the elements of the SPS be in the same standard - either include the "Protection System components" and "non-Protection System components" of a SPS in PRC-005 or in PRC-017, and not split the requirements for the testing of parts of the SPS into two standards. Since the specific requirements for the testing of the "Protection System components" of a SPS are already in PRC-005, it seems to make more sense to simply make PRC-005 apply to "all" components (parts) of a SPS rather than repeat the specific requirements for the testing in a second standard. It is not clear how a SPS can have "non-Protection System components". If a component is required in the composition of a SPS to achieve the desired operability, it seems implicit that it becomes a "Protection System component". Once the definition of a SPS is clearly determined (part of this project), the analysis of any operation (or lack of operation) of the scheme does not need to be treated any differently than other Protection System analysis and correct-operation determination. It is recommended that the evaluation of proper/improper operation of a SPS be included in PRC-004 rather than in a |

second Misoperation standard, PRC-016. Once the definition of a SPS is well defined, it should be no more or less difficult to determine if it operated correctly than any other protection scheme. The time frames for review, possible involvement of multiple parties, and Corrective Action Plans aspects apply directly to SPSs just as they do to ordinary Protection System schemes.

Group

Florida Municipal Power Agency

Frank Gaffney

No

FMPA appreciates the efforts of the team and believes the definition is a significant improvement over the former definition. There are only a few comments we are making in response to this and the next two questions First is that we are of the opinion that Special Protection Systems are indeed Protection Systems as defined in the NERC Glossary, and as applicable to PRC-005-2 recently approved by FERC. The Applicability Section of PRC-005-2 at 4.2.4 reads: "Protection Systems installed as a Special Protection System (SPS) for BES reliability." If an SPS is not a Protection System, then what is the scope of testing required in PRC-005-2 for an SPS? If an SPS is not a Protection System, should the scope of the SAR be changed to include modifications to PRC-005-2? The SDT seems to depend on: "... SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment" in expressing its opinion that SPSs are not Protection Systems; however, those terms are not used in the Glossary definition of Protection Systems. There is nothing in the definition of Protection System that would eliminate SPSs from being a subset of Protection Systems. In addition, under the section "Voltage Threshold" of the paper that includes the proposed definition, the paper states: "(a)ll elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements." If the SPS is not a Protection System that includes: (i) relays; (ii) communication systems; (iii) voltage and current sensing devices; (iv) dc supply; and (v) control circuits as elements of the Protection System, then to what does "all elements" refer?

No

The definition should not include brightlines. Brightlines already exist in at least two standards that would just cause confusion over what brightline to use. The CIP-002-5 standard has a Medium Risk brightline criteria 2.9 of Attachment 1 to CIP-002-5 which states: "2.9. Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable." IRO-005, R9 uses a criteria of: "... a Special Protection System that may have

an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) ..." Adding another set of brightlines (for no apparent purpose contained within the standards but presumably for the convenience of three of the Regions) that conflict with these brightlines already within the standards will only bring confusion. Brightlines for SPSs should be within each standard, not within the definition. If the SDT does not agree, then, at minimum, the SAR should be changed to modify CIP-002-5 and IRO-005 to align with the newly proposed brightlines. The definition is exceptionally long. By removing the categories and brightlines from the definition, it cuts the definition roughly in half.

The definition does not address automatic actions taken by an EMS, SCADA or DCS and whether that would be considered an SPS. For instance, an EMS can be programmed to perform automated switching (without human intervention) to relieve an overloaded Facility in a similar manner to an SPS designed with relays or a programmable logic controller. Would such automation cause the EMS to be an SPS and subject to PRC-005-2 requirements for testing?

Individual

Catherine Wesley

PJM Interconnection

Yes

Based on the high level information included in the SAR, PJM offers the following comments: a. Recommend a new name for the project. It is not a phase 2 of the Protection Misoperation standard effort as identified. It is a new project covering all aspects of SPSs, and the present Project numbering and project name are confusing. b. Specific to the strawman definition, for 'd' in the listing of schemes that do not constitute an SPS, the list of equipment is very discrete/specific. Please revise to be more generic because if not revised, could possibly leave out emerging technologies requiring future revision. c. For the classifications identified, they should be static in their scope, not dynamic which would result in potentially continued reevaluation of the classifications. In other words, base the SPS types on the contingency mitigated not the results of the contingency. d. PJM is reluctant to support adding the BA to the applicability of the standard since it is administrative in nature; however, understands that the BA is the source of the information (the largest generator unit in the BA area). Alternatives to making a new administrative requirement include using the data request section of the RoP (section 1600). e. The standard should not allow new permanent SPSs except for temporary installations that will eventually be removed when permanent mitigation is built or for maintenance conditions.

No

Individual

Bill Fowler

City of Tallahassee



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| Yes  |
| While TAL appreciates the need for consistency among regions in regards to the classification of SPS, flexibility in this classification should be afforded the regions due to valid geographical concerns. For this reason, TAL believes the classification component of the proposed language should be independently developed from the SPS definition. |
| No   |
|  |
| N/A  |
| Individual   |
| Karen Webb   |
| City of Tallahassee - Electric Utility   |
| Yes  |
| While TAL appreciates the need for consistency among regions in regards to the classification of SPS, flexibility in this classification should be afforded the regions due to valid geographical concerns. For this reason, TAL believes the classification component of the proposed language should be independently developed from the SPS definition. |
| Yes  |
| TAL believes valid geographical concerns exist among regions, and therefore some flexibility should be afforded in the classification of SPS.  |
|  |
| Individual   |
| Scott Langston   |
| City of Tallahassee  |
| Yes  |
| While TAL appreciates the need for consistency among regions in regards to the classification of SPS, flexibility in this classification should be afforded the regions due to valid geographical concerns. For this reason, TAL believes the classification component of the proposed language should be independently developed from the SPS definition. |
| Yes  |
| TAL believes valid geographical concerns exist among regions, and therefore some flexibility should be afforded in the classification of SPS.  |
| TAL provides no comment  |
| Group  |
| PacifiCorp   |
| Sandra Shaffer   |
| No   |
|  |
| Yes  |

PacifiCorp agrees with the Industry Need statement for this project and that the existing NERC Glossary of Terms definition for a Special Protection System (SPS) or Remedial Action Scheme (RAS) as used in the Western Interconnection lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions. This leads to inconsistent application of the SPS-related NERC Reliability Standards. Phase 1 of Project 2010-05.1 addresses Misoperations of Protection Systems (PRC-004-03). The implementation Plan for PRC-004-03 will require the Western Electricity Coordinating Council (WECC) to modify Regional Reliability Standard PRC-004-WECC-1 which has an attached Table, Major WECC Remedial Action Schemes (RAS). As this Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) is addressing all aspects of Special Protection Systems, including misoperations, NERC should instruct WECC to review the PRC-004-WECC-1 Table, Major WECC Remedial Action Schemes (RAS), and, to the extent possible, conform to NERC SPS/RAS definitions and classifications developed in Project 2010-05.2 SPS Phase 2. In addition, the purpose of WECC Criterion PRC-(012 through 014)-WECC-CRT-2 is to (1) establish a documented RAS review procedure to ensure compliance with PRC-012-0, (2) establish a RAS database per PRC-013-0, and (3) meet the Regional Reliability Organization / Reliability Assurer requirements of PRC-014-0. This regional criterion will require modification upon completion of Project 2010-05.2 SPS Phase 2, which is expected to provide a continent-wide definition and classification of SPS/RAS.

Individual

Gul Khan

Oncor Electric Delivery Company LLC

No

See response to Question 3 which addresses Oncor's comments regarding the System Protection Control Subcommittee (SPCS) Technical Report.

No

The purpose of this SAR is stated to "develop continent-wide standards to address all aspects of SPS." Oncor interprets this to mean regional variance is not considered.

With respect to the System Protection Control Subcommittee (SPCS) Technical Report (Report), Oncor provides the following comments. First, Oncor agrees with the proposed SPS definition and encourages the SDT to keep the following in the exclusions; Static Var Compensators (SVCs), Series/Shunt Capacitors, and Series/Shunt Reactors. Oncor believes these devices, as used today, are part of "standard" business practice. Additionally, Oncor has general concern about the SPS Operations Review Process as described on Page 23 of the Report. SPS design is based on long-range planning data provided by the Planning Authority. Tools to perform in depth real-time analysis are limited. Oncor believes that the immediate assessment of an SPS operation should be limited to considering if it operated as designed. As proposed in Appendix C of the Report, the new PRC-016 requirement which replaces PRC-012-0 R1.7, adds real time SPS operation analysis. Oncor recommends the

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| SDT not require this level of analysis to PRC-016 and indicate that the SPS Operations Review Process is for Mis-Operations only.  |
| Individual   |
| Nazra Gladu  |
| Manitoba Hydro   |
| Yes  |
| (1) In the "Brief Description" section of the SAR, it is stated that the project will develop a standard to address the "periodic comprehensive SPS assessments". Are the periodic comprehensive SPS assessments necessary given that an initial review has been completed and annual assessments of SPS have been included in the transmission planning studies?  |
| No   |
| (1) General comment as a reminder to the SDT, consider keeping the new standard as simple as possible and of minimum length. (2) General comment - consider replacing all instances of the word "standard" with "NERC Reliability Standard". (3) Page 3 - capitalize the word "data" in the title for PRC-015-0 Special Protection System data and Documentation. (4) Page 3 - capitalize and re-write "bulk power system" as "Bulk-Power System". (5) Page 3 - a 'period' is missing after the text ".....into a Reliability Standard".   |
| Group  |
| ACES Standards Collaborators   |
| Jason Marshall   |
| Yes  |
| (1) In general, we are supportive of the concept of the SAR. We support developing a more specific definition of SPS for consistent application and classification of SPSs across all NERC regions. However, we do have some specific concerns identified below. (2) The SAR should clarify what is meant by "planning, coordination, and design" and "review, assessment, and documentation" of SPS. If by "planning, coordination, and design," the SAR intends to consider which facilities the SPS will open by performing planning studies and to consider their impacts on one another in the same studies, we are supportive. If the engineering design (e.g. such as what relays will be used, what CT settings will be) is what is intended, we do not support the SAR as it is inconsistent with any other standard. For example, there is no engineering design standard for Protection Systems. This would extend the standards beyond what the original intention of the fill-in-the-blank unapproved standards. Furthermore, inclusion of "review" and "assessment" is part of the confusion because we interpret this to mean the analysis that is performed in the planning studies. Please clarify. (3) In the "Brief Description" section, what is the difference between "annual assessments of SPS in transmission planning studies" and "periodic comprehensive SPS assessments?" Annual would be periodic. Please provide clarification. |
| No   |
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| (1) We have no additional comments. Thank you for the opportunity to comment.  |
| Individual   |
| David Jendras  |
| Ameren   |
| Yes  |
| (1) Will the term RAS be eliminated, such that SPS is used consistently by all eight regions? If RAS is retained then the statement "Also called Remedial Action Scheme" from the present definition also needs to be retained. (2) Is our understanding correct that the scope is to be limited to the 693 reliability standards?   |
| No   |
| We believe that the term 'system' is used in a myriad of ways in the NERC Glossary of Terms. Thus we request revising the first sentence of the proposed SPS definition from the SAMS-SPCS SPS Technical Reference to clarify 'system'. We recommend the following: 'A scheme designed to detect predetermined Bulk Electric System (system) conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.' |
| Group  |
| Bonneville Power Administration  |
| Andrea Jessup  |
| No   |
| No   |
| Group  |
| SPP Standards Review Group   |
| Robert Rhodes  |
| Yes  |
| We are concerned that the scope of this project may creep beyond the true purpose of Special Protection Systems into the area of protection schemes used for individual facilities. While we believe this is covered in the accompanying SPCS report, it is not spelled out specifically in the SAR. It needs to be included to keep the SDT on track.   |
| No   |
| While we realize this is a standard question on SAR postings, it seems odd that it is included in a project that is intended to pull the differing interpretations of SPS from the individual Regions into a single, continent-wide effort. This being the case, we hope that regional differences can be put aside.   |

We note the effort within the SPCS report to clearly state that SPS are not truly Protection Systems and an effort was made to use lower case protection systems to stay away from the conflict. This being the case, perhaps we should defer to the naming convention used in WECC and designate these systems Remedial Actions Schemes.

## Problem Statement

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards.

## Background

### NERC Definitions

The existing NERC *Glossary of Terms* defines an SPS and RAS as:

#### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

In this document, use of the term SPS in general discussions and proposals for future definitions and standards apply to both SPS and RAS. Specific references to existing practices within Regions use the term SPS or RAS as appropriate for that Region.

The NERC *Glossary of Terms* defines a Protection System as:

#### *Protection System*

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Inclusion of the words “protection system” in the term Special Protection System has raised questions whether this is an intentional reference such that SPS are a subset of Protection Systems. Use of protection system (lower case) within the SPS definition identifies that SPS are not Protection Systems. While SPS may include the same types of components as Protection Systems, SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment. SPS may, for example, effect a change to the operating state of power system elements to preserve system stability or to avoid unacceptable voltages or overloads in response to system events. There are many reasons for implementing an SPS; for example, an SPS can be implemented to ensure compliance with the TPL Reliability Standards, to mitigate temporary operating conditions or abnormal configurations (e.g., during construction or maintenance activities), or in instances where system operators would not be able to respond quickly enough to avoid adverse system conditions.

A second area in which the existing SPS definition lacks clarity is the actions that are characteristics of SPS. The actions listed in the definition are broad and may unintentionally include equipment whose purpose is not

expressly related to preserving system reliability in response to an event. Inclusion of any system taking “corrective action other than ... isolation of faulted components to maintain system reliability” could be deemed to include equipment such as voltage regulators and switching controls for shunt reactive devices. This inclusion would then make these elements subject to single component failure considerations (sometimes referred to as redundancy considerations), coordination, reporting, and maintenance and testing requirements that may be required in the NERC Reliability Standards related to SPS.

This report proposes a revised definition of SPS to address these issues. Development of the proposed definition considered other definitions, common applications, and existing practices regarding classification of SPS.

## Chapter 1 – SPS Definition

### Considerations for a Revised Definition

#### Common Application of SPS in Industry

Most SPS are used to address a range of system issues including stability, voltage, and loading concerns. Less common applications include arresting sub-synchronous resonance and suppressing torsional oscillations. Actions taken by SPS may include (but are not limited to): system reconfiguration, generation rejection or runback, load rejection or shedding, reactive power or braking resistor insertion, and runback or fast ramping of HVdc.

SPS are often deployed because the operational solutions they facilitate are substantially quicker and less expensive to implement than construction of transmission infrastructure. Permanent SPS have been implemented in some cases where the cost associated with system expansion is prohibitive, construction is not possible due to physical constraints, or obtaining permits is not feasible. In other cases temporary SPS have been implemented to maintain system reliability until transmission infrastructure is constructed; or when a reliability risk is temporary (e.g., during equipment outages) and the expense associated with permanent transmission upgrades is not justified.

The deployment of SPS adds complexity to power system operation and planning:

“Although SPS deployment usually represents a less costly alternative than building new infrastructure, it carries with it unique operational elements among which are: (1) risks of failure on demand and of inadvertent activation; (2) risk of interacting with other SPS in unintended ways; (3) increased management, maintenance, coordination requirements, and analysis complexity.”<sup>1</sup>

#### Classification of SPS Types

Three regions classify SPS according to various criteria, including the type of event the SPS is designed to address as well as the ability of the SPS to impact on a local versus wide-area reliability. Also in this context, what constitutes local versus wide-area varies among Regions and is not based on the NERC glossary term Wide Area, which is specific to calculation of Interconnection Reliability Operating Limits (IROL).<sup>2</sup>

SPS classification differentiates the reliability risk associated with SPS and provides a means to establish more or less stringent requirements consistent with the reliability risk. For example, it may be appropriate to establish less stringent requirements pertaining to monitoring or single component failure of SPS that present a lower reliability risk. A recommendation for classification of SPS is included with the proposed definition and subsequent discussion of standard requirements includes recommendations where different requirements based on classification are deemed appropriate.

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<sup>1</sup> McCalley, et al, “System Protection Schemes: Limitations, Risks, and Management”, PSERC Publication 10-19, Dec 2010.

<sup>2</sup> The NERC Glossary defines Wide Area as “The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.”

## Common Exclusions from the SPS Definition in Industry

Exclusions provide a means to assure that specific protection or control systems are not unintentionally included as SPS. The NERC glossary definition of SPS states that “An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS).”

Even with the exclusions in the NERC definition, other commonly applied protection and control systems meet the general language in the SPS definition. Considerable effort has been expended by industry discussing what systems are SPS. NPCC and SERC have documented examples of exclusions to the SPS definition in their regional guidelines. NPCC explicitly excludes “Automatic underfrequency load shedding; Automatic undervoltage load shedding and manual or automatic locally controlled shunt devices.”<sup>3</sup> SERC’s SPS guideline calls out specific exclusions as follows:

- a. UFLS and/or UVLS,
- b. Fault conditions that must be isolated including bus breakup / backup / breaker failure protection,
- c. Relays that protect for specific equipment damage (such as overload, overcurrent, hotspot, reclose blocking, etc.),
- d. Out of step relaying,
- e. Capacitor bank / reactor controls,
- f. Load Tap Changer (LTC) controls,
- g. Automated actions that could be performed by an operator in a reasonable amount of time, including alternate source schemes, and
- h. Scheme that trips generation to prevent islanding

A recommended list of protection and control systems that should be excluded from classification as SPS is included with the proposed definition.

### Exclusion for Operator Aides

SAMS and SPCS considered a number of factors in discussing this subject including:

- 1) whether the actions are required to be completed with such urgency that it would be difficult for an operator to react and execute in the necessary time, and
- 2) whether the required actions are of such complexity or across such a large area that it would be difficult for an operator to perform the actions in the necessary time.

It is difficult to address these questions with concise and measurable terms, making it difficult to explicitly exclude them in the definition without introducing ambiguous terms counter to the objective of providing needed clarity in the SPS definition. Whether its existence is based upon convenience or not, any automated system with the potential to impact bulk power system reliability should be defined and expressed to the appropriate authority (e.g., Planning Coordinator, Reliability Coordinator) for the purposes of system modeling and coordination studies, to ensure that these systems are properly coordinated with other protection and control systems, and to ensure that inadvertent operations do not result in adverse system impacts.

On these bases, SAMS and SPCS decided not to provide an exclusion for schemes based on a general criterion as to whether the scheme automates actions that an operator could perform in a reasonable amount of time or schemes installed for operator convenience. However, SAMS and SPCS do recommend exclusions for specific applications that meet these criteria such as automatic sequences that are initiated manually by an operator. Furthermore, any

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<sup>3</sup> NPCC *Glossary of Terms Used by Directories*



scheme that is not installed “to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, an extreme event, or Cascading” would be excluded by definition, regardless of whether it is installed to assist an operator.

### Voltage Threshold

All elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.

### Proposed Definition

The proposed definition clarifies the areas that have been interpreted differently between individual entities and within Regions, in some cases leading to differing regional definitions of SPS. The proposed definition provides a framework for differentiating among SPS with differing levels of reliability risk and will support the drafting of new or revised SPS standards.

#### *Special Protection System (SPS)*

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

- a) Underfrequency or undervoltage load shedding
- b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature
- c) Autoreclosing schemes
- d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers
- e) Schemes that prevent high line voltage by automatically switching the affected line
- f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open
- g) Out-of-step relaying
- h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty
- j) Automatic sequences that proceed when manually initiated solely by an operator
- k) Sub-synchronous resonance (SSR) protection schemes

- l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards.

- Type PS (planning-significant): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type PL (planning-limited): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.
- Type ES (extreme-significant): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type EL (extreme-limited): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.

An SPS is classified as having a significant impact on the BES if failure or inadvertent operation of the scheme results in any of the following:

- Non-Consequential Load Loss  $\geq$  300 MW
- Aggregate resource loss (tripping or runback of generation or HVdc)  $>$  the largest Real Power resource within the interconnection<sup>4</sup>
- Loss of synchronism between two or more portions of the system each including more than one generating plant
- Negatively damped oscillations

If none of these criteria are met, the SPS is classified as having a limited impact on the BES.

## Definition of Significant and Limited Impact

The parameters used to define the bright line between “significant” and “limited” impacts are proposed to consider only the electrical scale of the event. Defining the bright line in this way eliminates the difficulty in distinguishing the geographic impact of an SPS as either “wide” or “local.”

NERC Standard EOP-004-1, DOE Form OE-417 Electric Emergency Incident and Disturbance Report, establishes the criteria by which an event is categorized as a Disturbance and requires a disturbance report. In terms of SPS, the proposed criteria for significant impact mirrors EOP-004-1 by including a non-consequential load loss value of 300 MW.

NERC Reliability Standards require consideration of loss of any generating unit; therefore, generating unit loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the

<sup>4</sup> I.e., Eastern, Western, ERCOT, or Quebec Interconnection.

interconnection. The generation loss level was selected as a loss greater than the largest unit within an interconnection on this basis.

Tripping multiple generating units exceeding the capacity of the largest unit within an interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requiring detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators, combined with the loss of load criterion, are proposed to identify the potential reliability risk associated with failure of a SPS. Subsequent sections of this report recommend requirements for assessment and design of SPS based on whether the potential reliability risk associated with the SPS are significant versus limited impacts.

The proposed thresholds differentiate between significant and limited impact. While it should be clear there is no upper threshold on what constitutes a significant impact, there also is no lower threshold proposed as to what constitutes limited impact. Whether a scheme is an SPS is determined by the definition; significant and limited impact are used only to classify SPS. For example, if a scheme is installed to meet system performance requirements identified in the NERC Reliability Standards then it is an SPS regardless of its potential impact. A failure of the SPS would result in a violation of a NERC Reliability Standard. Thus, excluding a scheme with impact below a certain threshold would undermine the reliability objective of the standard requirement the scheme is installed to address.

# Unofficial Comment Form

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Special Protection System

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the revised definition of Special Protection System. The electronic comment form must be completed by **8 p.m. Eastern, on Wednesday, April 9, 2014**.

If you have questions please contact [Al McMeekin](#) via email or by telephone at (803) 530-1963.

The project page may be accessed by clicking [here](#).

### Background Information

The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or Remedial Action Scheme (RAS), as used in the Western Interconnection, lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions. This leads to inconsistent application of the SPS-related Reliability Standards. At the request of the NERC Standards Committee, the Planning Committee directed the System Protection and Control Subcommittee (SPCS) to research this issue. The SPCS along with the System Analysis and Modeling Subcommittee (SAMS) authored the technical [report](#) posted in full on this project's web page. An excerpt of that report containing the rationale for the draft definition of an SPS is also provided for this informal comment posting.

The drafting team will use the draft definition developed by SPCS and SAMS as a starting point for developing a revision to the term, Special Protection System (SPS), found in the Glossary of Terms Used in NERC Reliability Standards. The revised term will form the basis for revising the existing SPS-related standards. Your comments on the draft definition are much appreciated and will aid the drafting team in developing a quality definition of SPS for stakeholder consideration and ballot.

### Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Does the proposed definition properly identify the types of protection schemes that should be subject to the SPS-related standards? If not, please explain your concerns and how you would address them.

Yes

No

Comments:

2. Do you agree with categorizing SPSs into the four proposed types? If not, please explain your concerns and how you would address them.

Yes

No

Comments:

3. If you have any other comments on this definition that you haven't already mentioned, please provide them here:

Comments:

## Standards Announcement

### Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Special Protection System

Informal Comment Period Now Open through April 9, 2014

#### [Now Available](#)

A 30-day informal comment period for the **Revised Definition of Special Protection System** is open through **8 p.m. Eastern on Wednesday, April 9, 2014.**

If you have questions please contact [Al McMeekin](#) via email or by telephone at (803) 530-1963.

Background information for this project can be found on the [project page](#).

#### **Instructions for Commenting**

Please use the [electronic form](#) to submit comments on the revised definition. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

For information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Wendy Muller](#),  
Standards Development Administrator, or at 404-446-2560.*

North American Electric Reliability Corporation  
3353 Peachtree Rd, NE  
Suite 600, North Tower  
Atlanta, GA 30326  
404-446-2560 | [www.nerc.com](http://www.nerc.com)

**Individual or group. (46 Responses)**

**Name (29 Responses)**

**Organization (29 Responses)**

**Group Name (17 Responses)**

**Lead Contact (17 Responses)**

**IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (2 Responses)**

**Comments (46 Responses)**

**Question 1 (44 Responses)**

**Question 1 Comments (44 Responses)**

**Question 2 (41 Responses)**

**Question 2 Comments (44 Responses)**

**Question 3 (0 Responses)**

**Question 3 Comments (44 Responses)**

|   |
|---|
|   |
| Individual  |
| Aaron Staley  |
| Orlando Utilities Commission  |
|   |
| Yes   |
| Voltage Threshold question: By "performance issues on the bulk electric system" does this mean the response of the bulk electric system (as in loading/voltage)? Or does it mean an outage on the bulk electric system? For example a SPS type system installed solely on non bulk electric equipment designed to protect solely the non bulk electric equipment but is triggered by an outage on the bulk electric system? |
| Yes   |
| A question on the difference between type Planning and type Extreme. The Planning type references the system performance requirements in the NERC standards, but the Extreme lists the impact of two or more elements removed. How would an SPS installed to keep the system within the performance requirements for a TPL 003 C2 event be categorized?   |
| Excellent Job!  |
| Individual  |
| Barb Kedrowski  |
| Wisconsin Electric Power Co   |
| Agree   |
| NAGF  |
| Individual  |
| Chris Scanlon   |
| Exelon  |

|   |
|---|
|   |
| Yes   |
|   |
| Yes   |
|   |
| None at this time. We look forward to providing comments when the standard is posted.   |
| Group   |
| NERC Compliance Policy  |
| Randi Heise   |
|   |
| No  |
|   |
| No  |
|   |
| Dominion suggests use of a single term, Special Protection System, thus elimination of the term "Remedial Action Scheme" for consistency across the Regions.  |
| Individual  |
| Andrew Z. Pusztai   |
| American Transmission Company, LLC  |
|   |
| Yes   |
| The scope of the SAR should establish a definition for "functional modification." Functional modifications require SPS owners to have Regional Entity (RE) review, but RE review teams are not given guidance on what constitutes a functional change. For instance, is a direct replacement of a failed SPS component failure (SEL-321 Relay for SEL-321 Relay) a functional change? How about upgrading a SEL-321 Relay with a SEL-421 Relay with the same logic? Based on the above, ATC recommends that the SDT consider adding a proposed definition of "functional modification" to the SAR as it relates to SPS. |
| No  |
|   |
|   |
| Individual  |
| John Seelke   |
| Public Service Enterprise Group   |
|   |
| Yes   |
|   |
| Yes   |



|  |
|--|
|  |
| Individual   |
| Karen Webb   |
| City of Tallahassee - Electric Utility   |
|  |
| Yes  |
|  |
| No   |
| It would be beneficial to entities maintaining SPS systems to have a readily available resource on the NERC website that provides guidance to entities on identifying the largest Real Power Source for the interconnection. More description of “negatively damped oscillations” is necessary to determine the scope of what the proposed language includes.              |
|  |
| Individual   |
| Bill Fowler  |
| City of Tallahassee  |
|  |
| Yes  |
|  |
| No   |
| It would be beneficial to entities maintaining SPS systems to have a readily available resource on the NERC website that provides guidance to entities on identifying the largest Real Power Source for the interconnection. More description of “negatively damped oscillations” is necessary to determine the scope of what the proposed language includes.              |
| N/A  |
| Group  |
| DTE Electric   |
| Kathleen Black   |
| Agree  |
| Support NAGF members comments.   |
| Group  |
| ACES Standards Collaborators   |
| Jason Marshall   |
|  |
| No   |
| (1) We support the need to modify the existing definition based on the explanation in the supporting document. We agree that the existing definition lacks specificity, which leads to inconsistent application among the various NERC regions. We also agree that systems such as voltage controls on capacitor banks could be inadvertently included as SPS based on the |

existing definition. However, the proposed definition needs significant refinement as it introduces ambiguity and the purpose of the classification of SPS is not clear. (2) We suggest that the “system performance requirements identified in the NERC Reliability Standards” should be specified. This is overly broad and ambiguous and will only lead to inconsistent enforcement. Which system performance requirements in which standards? Would this apply to any standards or is it intended primarily to apply to TPL standards? Does this require the owner of the SPS to document for which standards the SPS is installed? For newly installed SPS, this might be easy but there could be disagreement over the purpose of the installation of existing SPS especially those that have been installed for a decade or more. Was it installed to meet NERC standards performance requirements or to address an operational issue or planning issue? We recommend identifying specific standards and requirements in the technical guideline section for clarity. (3) What is meant by the term “elements”? Element is a defined term in the NERC Glossary; however, it is not capitalized in the proposed SPS definition. This would imply something other than the meaning in the NERC glossary. Is it supposed to be capitalized? (4) Use of an “extreme event” is ambiguous and will lead to inconsistent compliance outcomes. Since the definition includes limiting impacts from the removal of two or more elements and Cascading, it is unclear what is meant by an extreme event. Cascading would certainly be an extreme event. However, three or more elements might not be an extreme event but one would think if two or more elements are included that three should be. In fact, three or more elements might not even be as severe as two or more elements. A three-terminal line could be considered three-elements. The bottom line is that this needs clarification. (5) Assuming that the proposed SPS definition intended to use the NERC glossary term Element, we suggest using the term Facility. Elements are a more fundamental component and can include circuit breakers. As the proposed definition is written, use of Element could be interpreted as including any scheme designed to respond to the clearing of a single facility. Because circuit breakers are considered Elements, any scheme designed to respond to the clearing of a line (i.e. removing two or more Elements or circuit breakers would fit the proposed definition and would clear the line) would be considered an SPS. We do not believe this was the intent given the use of limiting impacts for “extreme events” and “Cascading” as the other two reasons a scheme would be considered an SPS. (6) We suggest including a statement that makes it clear that the list of excluded schemes are not an exhaustive list. Otherwise, there may be disagreements over what is not an SPS which will lead to inconsistent applicability and compliance outcomes.

No

(1) Conceptually, we are not opposed to categorizing SPS into multiple tiers. However, the purpose of categorization is not clear and the proposed categories are ambiguous. What is the purpose of differentiating between an SPS that is designed to meet NERC reliability standards (planning) and one that is designed to limit the impacts of the loss of two or more elements, an extreme event or Cascading (extreme)? Limiting impacts on the BES are also related to multiple NERC reliability standards. Why are the extreme types of the definition called “extreme” when they include non-extreme events? Loss of two or more Elements could be the loss of a single transmission line or transformer since the definition of Element includes

circuit breakers. This is not extreme. (2) We support the description of significant as it is clear and unambiguous.

We have no additional comments and thank you for the opportunity to comment.

Group

SPP Standards Review Group

Robert Rhodes

No

We assume that generator AVRs and Power System Stabilizers (PSS) are not to be considered SPS. As such, AVRs and PSSs should be specifically excluded from the SPS definition by incorporation in the list of exclusions. Also Dynamic Voltage Regulators (DVRs) also fall into a similar category. Would the drafting team be willing to say that any protection schemes or devices used exclusively for the protection of a generator, and that only trip the generator in question, would not be considered an SPS?

No

Individual

Catherine Wesley

PJM Interconnection

No

For 'd' in the listing of schemes that do not constitute a SPS, the list of equipment is very discrete/specific. PJM recommends this list be more generic because if not revised, there is the possibility that emerging technologies would be left out, requiring future revision of the definition.

No

For the four types of SPSs identified, they should be static in their scope, not dynamic which would result in potentially continued reevaluation of the types. In other words, base the SPS types on the contingency mitigated, not the results of the contingency.

Group

MRO NERC Standards Review Forum

Joe DePoorter

No

The NRSF has concerns that the proposed SPS definition in the technical paper remains broad, lacks sufficient clarity and the specificity necessary for consistent identification and classification of SPS systems across all eight regions. While the SPCS effort is commendable, the definition remains overly broad and will continue to identify protection systems that don't affect the security of the BES. While having the SPS exclusions list provides some clarity and is

helpful, the presence of a long exclusions list shows the definition lacks the clarity and specificity necessary for the consistent identification and classification of SPS schemes. Since the drafting team cannot identify and exclude all possible protection schemes that respond to non-fault conditions, more protection systems will be identified by different regions in the future causing inconsistent application of the definition. The MRO NSRF suggests the drafting team consider enhancements including, definition adjustments, and the addition of a screening process to clearly communicate the SPS definition intentions while avoiding unduly identifying protection systems that should not be Special Protection Systems. The screening process is needed because an exhaustive list of exclusions cannot be developed. The NSRF suggests the drafting team consider a two-step screening and assessment process. Step 1: Screening process using an English definition designed to eliminate unnecessary analyses. Use the following definition to screen for inclusions and exclusions: Proposed definition additions and changes: Special Protection System (SPS) A scheme designed to detect predetermined system conditions and automatically take corrective actions on BES Facilities, other than the isolation of faulted elements, to meet BES system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading. Subject to the exclusions below, such schemes are designed to maintain BES system stability (not individual unit stability), acceptable BES system voltages, acceptable BES power flows, or to address other BES reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration. The following schemes do not constitute an SPS in and of themselves: a) Underfrequency or undervoltage load shedding b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, or power plant unbalance relays / controls. c) Autoreclosing schemes d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers e) Schemes that prevent high line voltage by automatically switching the affected line f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open g) Out-of-step relaying h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation, that may not be capable of maintaining acceptable frequency and voltage) i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty j) Automatic sequences that proceed when manually initiated solely by an operator k) Sub-synchronous resonance (SSR) protection schemes l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements n) Reverse power relays o) Synchronizing relays q) Relays or controls that prevent BES facilities to be backfed from a non-

BES system Step 2: Perform a security or stability analysis to verify that the SPS has a critical impact on BES system security. If the protection system meets the inclusions and is not excluded by the step 1 definition screen, perform a system security analysis. If the loss, misoperation, or non-operation of the protection system results in BES system instability, uncontrolled separation, and cascading, then the protection system is a SPS. If loss, misoperation, or non-operation of the protection system does not result in BES system instability, uncontrolled separation, and cascading, it is not a SPS. This equally effective or superior approach would concentrate on BES system security analysis (or stability verification), where security is defined as the ability to return to an acceptable equilibrium point within BES system emergency ratings while avoiding BES system instability, uncontrolled separation, and cascading. This is consistent with the RAI process of focusing on appropriate risk. BES protection systems designed to maintain BES system security appropriately separates Special Protections Systems (SPS's) as important enough to have their own NERC standard outside of the normal PRC protection system standards. BES security can be mathematically measured and quantified by existing power system stability programs. BES security refers to conditions where the BES system returns to an acceptable equilibrium point within BES system emergency ratings and where sufficient synchronizing and damping torques are available after identified TPL standard system disturbances to maintain acceptable BES system damping, avoid uncontrolled separation, and cascading. BES system damping can be further defined as an acceptable decreasing damped curve with an agreed upon damping ratio or a damped power system oscillation or sine wave whose amplitude approaches zero as time increases.

No

Comments: The four proposed types are unnecessary if a BES system security / stability analysis is added. An appropriate screening criteria coupled with a stability analysis is a superior way to identify BES system security impacts determining if a protection system should be subject to the standard. If a BES system security / stability analysis is added, the standard can be simplified to a binary approach without the four classifications. A protection system would be identified as either applicable or not applicable.

The proposed standard scope includes revising PRC-017-0. This standard is scheduled to be retired with the effective date of PRC-005-2, which is April 1, 2014. PRC-005-2 already includes in its scope the maintenance and testing requirements of the Protection System elements of a SPS. It is recommended that the maintenance and testing requirements of all of the elements of the SPS be in the same standard. Either include the "Protection System components" and "non-Protection System components" of a SPS in PRC-005 or in PRC-017, and not split the requirements for the testing of parts of the SPS into two standards. Since the specific requirements for the testing of the "Protection System components" of a SPS are already in PRC-005, it seems to make more sense to simply make PRC-005 apply to "all" components (parts) of a SPS rather than repeat the specific requirements for the testing in a second standard. It is not clear how a SPS can have "non-Protection System components". If a component is required in the composition of a SPS to achieve the desired operability, it seems implicit that it becomes a "Protection System component". Once the definition of a SPS is clearly determined (part of this project), the analysis of any operation (or lack of operation)

of the scheme does not need to be treated any differently than other Protection System analysis and correct-operation determination. It is recommended that the evaluation of proper/improper operation of a SPS be included in PRC-004 rather than in a second Misoperation standard, PRC-016. Once the definition of a SPS is well defined, it should be no more or less difficult to determine if it operated correctly than any other protection scheme. The time frames for review, possible involvement of multiple parties, and Corrective Action Plans aspects apply directly to SPSs just as they do to ordinary Protection System schemes.

Individual

Martyn Turner

LCRA Transmission Services Corp

No

The list of exclusions is helpful and is very thorough. However, there may be certain applications, actions, or schemes that exist today (or in the future) that could be incorrectly labeled as an SPS. We have some concern that certain schemes or actions not listed (e.g. single-pole tripping, phase shifter operation, etc) could erroneously or inadvertently be considered an SPS, so the list included in the definition should not be treated as an exhaustive list of exclusions. We recommend revising the definition language as follows: "Examples of The following schemes that do not constitute and SPS in and of themselves:"

Yes

na

Group

Puget Sound Energy

Dianne Gordon

No

For "Exclusions" in the textbox labeled "Special Protection System (SPS)", paragraph b), the definition of "element" needs to be clarified as to whether lines are included or not. For example, does a locally sensing thermal scheme applied to a line constitute an SPS?

No

Some clarifications need to be made as follows: 1. The process by which entity submitted RAS schemes are slotted for a specific category needs to be clarified. For example, does an entity submit a RAS scheme with a proposed category designation and WECC officially approves the designation? 2. Definitions for "Planning" vs. "Extreme" need to be spelled out similar to the way definitions for "Significant" and "Limited" are spelled out.

Group

PacifiCorp

Sandra Shaffer

No

The proposed SPS definition does not provide adequate clarity with respect to protection systems that isolate multiple elements for reasons other than fault clearing. Many common protection schemes that utilize breaker status contacts or lockout contacts to transfer trip multiple elements within a substation seem to meet the new SPS definition, despite limited potential impacts to the bulk electric system. For example, consider a scheme that utilizes a status contact on a line breaker to transfer trip a shunt capacitor within the substation in conjunction with line tripping. In this example, the scheme is hard-wired within the substation, and does not utilize any arming logic. The intent of the example scheme is to provide fast shunt device tripping and to provide additional redundancy for the shunt device voltage control. Under the draft definition, this scheme appears to meet the SPS criteria (and is not excluded under the list of schemes that do not constitute an SPS), as the shunt capacitor control is not based on locally-sensed voltage and system elements are tripped for a reason other than facilitation of fault clearing. Unless the drafting committee considers hard-wired transfer trip schemes local to a substation as SPS, the definition should be revised to exclude such schemes.

Yes

The proposed SPS types closely match the existing SPS classifications used in the WECC, with additional sub-classification of extreme event schemes provided under Type ES (extreme-significant) and EL (extreme-limited).

Group

Northeast Power Coordinating Council

Guy Zito

No

We do note that the SPS definition excludes what is traditionally considered to be “protection systems.” However, the existing NERC definition for Protection System does not exclude Special Protection Systems. This creates a problem for NERC. We recommend concurrently with this new SPS definition to modify the definition for Protection System to specifically exclude Special Protection Systems. Without doing so would create potential compliance conflicts.

The type classifications need to be clarified and and made consistent. For example, “two or more elements removed” can refer to TPL Planning Events P3, P4, P5, P6, and P7. By definition within the TPL Reliability Standard, these are NOT extreme events, but indeed are performance requirements. The proposed change makes the typing of a SPS clear and consistent with existing NERC Reliability Standards. To this end, suggest the following: For the PS and PL types, suggest changing “A scheme designed to meet system performance requirements identified in the NERC Reliability Standards,…” to “A scheme designed to meet system performance requirements identified in NERC Reliability Standard TPL-001-4 Table 1 –

Steady State & Stability Performance Planning Events,...” For the ES and EL types, suggest changing “A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading,...” to “A scheme designed to limit the impact of an extreme event(s) identified in NERC Reliability Standard TPL-001-4 Table 1 – Steady State & Stability Performance Extreme Events, or Cascading,...” Centrally controlled undervoltage load shedding schemes should be covered by the new SPS definition. These are consistent with the nature of SPS regarding the complexity of the control logic and the effect of a single component failure on their reliable performance.

Individual

Dale Fredrickson

Wisconsin Electric Power Company

No

We suggest there needs to be a clearer distinction between a normal Protection System and an SPS. The clause in the 1st paragraph...”other than the isolation of faulted elements” should be expanded to recognize both faults and abnormal operating conditions. We recommend revising this paragraph to read: “A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of elements for faults or abnormal operating conditions, to meet system performance requirements identified in the NERC Reliability Standards...”. We also suggest that other exclusions should be allowed for generator overfrequency/underfrequency and turbine overspeed protection. We recommend revising Exclusion d) to read: “Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, generator over/under frequency protection, turbine overspeed protection, and tap-changing transformers.”

Yes

Individual

Michael Haff

Seminole Electric Cooperative, Inc.

No

The proposed definition for SPS includes a list of exclusions, “a” through “m”. Specifically, exclusion “b” states: “Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature.” Seminole requests that the following revisions to exclusion “b” be made: (1) The addition of the word “overload/” before equipment; (2) The addition of the following: “or eliminating the overload so as not to exceed the facility’s SOL” after the word “element;” and (3) The addition of the following: “or overload protection schemes” after the word



temperature. Exception “b” would then read as such: “Locally sensing devices applied on an element to protect it against overload/equipment damage for non-fault conditions by tripping or modifying the operation of that element or eliminating the overload so as not to exceed the facility’s SOL, such as, but not limited to, generator loss-of-field, or transformer top-oil temperature, or overload protection schemes.” Seminole believes that this revised language will allow for certain schemes that are delineated within the second paragraph of the proposed definition that states: “...such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may “execute actions that include” but are not limited to: changes in MW and Mvar output, “tripping of generators” and other sources, load curtailment or tripping, or system reconfiguration.” (emphasis added) Seminole would like to propose the following example for the drafting team to include in any supporting documentation for the proposed definition that touches on the revised exclusion “b”: Example: An entity has 1000 MW of generation interconnected at a common collector bus with three (3) 115 kV transmission lines emanating from the collector bus, two of the three lines share a common structure for greater than one mile. Each line is able to carry 600 MW; however, for the common structure contingency event (i.e., 2 out of the 3 circuits are lost simultaneously) the one remaining line overloads beyond its SOL rating. The event does not create an IROL but it does in fact cause the non-faulted facility to go beyond its SOL. The respective entity installs an automatic overload protection scheme that trips generation in the event the contingency was to occur as to not exceed the facility’s SOL. The automatic overload protection scheme should fall under exclusion “b” of the SPS proposed definition.

Yes

No additional comments

Individual

Thomas Foltz

American Electric Power

Yes

The proposed SPS definition appears to sufficiently identify the types of protection system schemes that should be subject to the SPS-related standards. However, the definition does not clearly indicate the line between what physical equipment is or is not part of the SPS. Consider a scheme that detects a system condition and subsequently decreases MW output of a unit. It is unclear if the SPS is 1) only those components that detect the system condition i.e. Transmission protective relays, voltage and current sensing devices etc., 2) only those components that decrease the MW output of the unit i.e. the turbine control system, associated logic, steam valves, etc. or 3) both sets of components. AEP recognizes that the SDT may prefer to address this issue within the SPS standards instead of the definition. Regardless, due to regional differences, we urge the SDT to clearly provide guidance.

No

The categorization between “significant” and “limited” may become problematic where an SPS falls on or near the given load and generation loss boundaries. Varying system conditions may cause a given SPS to qualify at times and not qualify at others with respect to the load loss or the loss of synchronism or oscillation criteria. Some SPSs that might ordinarily qualify as limited may have far ranging consequences under stressed interconnected system conditions because of their location. The significant-limited distinction should be removed. Categorization between “planning” and “extreme” events should not have the same issue with SPSs falling on or near a classification boundary, so we believe this classification is acceptable and may be useful with respect to the need for redundancy. We would, nevertheless, recommend more specific wording identifying the specific NERC standards, and clarifying that SPSs intended for those TPL planning events that involve two elements removed are, in fact, planning SPSs and thus not also extreme SPSs at the same time. We believe the TPL standards are implied here because of the terms “planning” and “extreme” events. Are there others? We don’t believe so.

Individual

David Jendras

Ameren

Yes

Yes

We are generally in agreement with the categorization of SPSs into the 4 buckets.

Please realize that the term “system” is used in a myriad of ways in the NERC Glossary of Terms. Thus we request revising the first sentence of the proposed SPS definition from the SAMS-SPCS SPS Technical Reference to clarify “system”. We recommend the following: “A scheme designed to detect predetermined Bulk Electric System (system) conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.”

Group

Iberdrola USA

John Allen

Yes

No

The type classifications are vague and inconsistent – for instance, “two or more elements removed” can refer to TPL Planning Events P3, P4, P5, P6, and P7. By definition within the TPL Reliability Standard, these are NOT extreme events, but indeed are performance

requirements. Proposed changes below make the typing of an SPS clear and consistent with existing NERC Reliability Standards. - For the PS and PL types, change “A scheme designed to meet system performance requirements identified in the NERC Reliability Standards,...” to “A scheme designed to meet system performance requirements identified in NERC Reliability Standard TPL-001-4 Table 1 – Steady State & Stability Performance Planning Events,...” - For the ES and EL types, change “A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading,...” to “A scheme designed to limit the impact of an extreme event(s) identified in NERC Reliability Standard TPL-001-4 Table 1 – Steady State & Stability Performance Extreme Events, or Cascading,...”

No other comments

Individual

Oliver Burke

Entergy Services, Inc.

Yes

Yes

Group

SERC Protection and Controls Subcommittee

David Greene

Yes

Yes

Please inform the SDT that the term ‘system’ is used in a myriad of ways in the NERC Glossary of Terms. Thus we suggest revising the first sentence of the proposed SPS definition from the SAMS-SPCS SPS Technical Reference to clarify ‘system’. We suggest: ‘A scheme designed to detect predetermined Bulk Electric System (system) conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.’ The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Individual

Jonathan Meyer

Idaho Power Company

|   |
|---|
| No  |
| Idaho Power Power Production department: Yes Idaho Power System Protection: No While we do feel the proposed definition lays the framework for identification of SPS/RAS schemes, there is sufficient vague language in the exclusions to result in doubt about the efficacy of the definition. In our own review of the definition we spent most of our time examining specific scenarios present in our own system and attempting to apply the definition without a clear result. We would like more detail in the exclusions detailing why those schemes are not SPS/RAS to assist with the application of the definition  |
| Yes   |
| We like the categorizing SPS based on impact, but it is difficult to comment further until the Requirements associated with these categories are written. In the context of the definition, we do not think they add clarity and should be part of the Project Standards but not part of the definition. If they were modified to be part of an identification process, much of our concern in response 1 could be alleviated. Rather than identify an SPS/RAS then categorize it, could the categories be used as part of the identification process? These classifications could make the identification process impact/performance based and could increase reliability by eliminating interpretation errors with the definition and exclusions. |
| In addition, to the above comments, we also agree with some members of the DT the use of "Special Protection System", specifically the use of word protection, could create confusion among Entities when considered with other "Protection Systems". The definition of a SPS should clarify the difference, and in addition, we favor adopting the "Remedial Action Scheme" moniker for this project and its resulting documents to avoid confusion for those Standards specific to "Protection Systems".  |
| Individual  |
| Bob Steiger   |
| Salt River Project  |
|   |
| Yes   |
| SRP has no concerns regarding the definition and the exclusions.  |
| Yes   |
|   |
|   |
| Individual  |
| Nazra Gladu   |
| Manitoba Hydro  |
|   |
| No  |
| 1.Should the term "NERC Reliability Standards" in this proposed SPS definition be replaced by "NERC TPL Reliability Standards" or simply "NERC TPL-001-4 Standard"? 2.For clarity, consider replacing the following sentence "The following schemes do not constitute an SPS in and of  |

themselves” with “The following schemes do not constitute an SPS”. 3.The wording of “to limit the impact of: two or more elements removed, an extreme event, or Cascading” is unclear. Does this imply that any scheme that removes two or more elements should be included as SPS? 4.In exclusion category b), consider adding the text “element overload protection that removes the element itself from service only” in the sentence so it reads “such as, but not limited to, element overload protection that removes the element itself from service only, generator loss-of-field or transformer top-oil temperature”. 5.In exclusion category f), consider replacing the words “non-fault operation” with “non-fault condition”. 6.In exclusion category i), consider replacing the words “fault duty” with “fault current”.

Yes

Individual

John Miller

Georgia Transmission Corporation

No

The new definition appears to be based on "what is not". Please supply clarification for item L). If a Static Var Compensator was applied to avoid a FIDVR condition in the BES but not angle damping or frequency damping, is it then considered a SPS?

Yes

GTC is in support of the comments from SERC-PCS

Group

Dominion

Mike Garton

Yes

Yes

Dominion agrees that there is benefit to having different categories or classes of SPS. However, the proposed classifications need additional clarity. The document states “The planning classification applies to schemes designed to meet system performance requirements identified in the NERC Reliability Standards”. It would be beneficial if the specific standards or class of standards (TPL?) were identified in this sentence. We also propose that extreme limited either be renamed or a 5th category be created. Our reason for this is that limited indicates ‘no significant impact’ whereas extreme seems to indicate something that is definitely not insignificant. We also propose that “aggregate resource loss (tripping or runback of generation or HVdc) greater than the largest Real Power resource

within the interconnection” be replaced with a bright line value such as is used in CIPsv5 or EOP-004.

1. Suggest spelling out FACTS 2. EOP-004-1 as mentioned in the document, needs to be updated as EOP-004-2

Group

Duke Energy

Michael Lowman

Yes

Duke Energy agrees that the proposed definition properly identifies the types of protection schemes that should be subject to the SPS-related standards. We ask that the SDT verify that centrally-controlled undervoltage-based load shedding is included in the definition of a Special Protection System. This was mentioned in the rationale of Project 2008-02 Undervoltage Load Shedding.

Yes

Duke Energy agrees with categorizing SPSs into four proposed types.

Individual

Anthony Jablonski

ReliabilityFirst

No

ReliabilityFirst submits the following comments for consideration: 1. ReliabilityFirst submitted a redline version of the proposed definition to the SDT coordinator (Al McMeekin) under a separate cover. 2. ReliabilityFirst has noticed that within the Project 2008-02 (Undervoltage Load Shedding) rationale for the definition of UVLS, the SDT indicated " Centrally-controlled undervoltage-based load shedding is excluded, because the load shedding logic may utilize 1) voltage inputs from multiple locations; and/or 2) inputs other than voltages, such as generator reactive reserves, facility loadings, and equipment statuses. As such, its reliable performance could be affected by a single component failure, which is consistent with the nature of Special Protection Systems. Therefore, the drafting team has recommended that Project 2010-05.2 Protection System (Special Protection Systems) include centrally-controlled undervoltage-based load shedding in the definition of a Special Protection System." Based on this rational, ReliabilityFirst requests clarification whether the SDT considered including centrally-controlled undervoltage-based load shedding in the definition of a Special Protection System? Without centrally-controlled undervoltage-based load shedding included in the proposed SPS definition, there could be a gap in coverage. 3. The term "fault" is used throughout the definition though it is not capitalized. ReliabilityFirst recommends capitalizing the term "fault" so it is consistent with the NERC Glossary of Terms definition of "Fault". 4. For item "e", ReliabilityFirst does not understand how schemes that prevent high line voltage by automatically switching the affected line are not considered an SPS. Such schemes are

designed to maintain acceptable voltages by reconfiguring the system (i.e., automatically switching the affected line). ReliabilityFirst requests the rationale for excluding this as an SPS. 5. For item “j”, the term “operator” is used. ReliabilityFirst requests clarification on the meaning of this term and believes the definition should identify the “operators” in which the definition is referencing. For example, is the definition meant to address transmission operators, substation operators, etc.? ReliabilityFirst believes the intent is transmission system operators and recommends the following for consideration: “Automatic schemes manually armed solely by a transmission system operator.”

No

ReliabilityFirst submits the following comments for consideration. 1. ReliabilityFirst does not understand why the categorization of SPS (i.e., the four distinct types), are included with the SPS definition. ReliabilityFirst believes the definition should simply state what is and what is not considered a SPS and the specific categorization is more appropriate to be placed within the individual standards themselves. Furthermore, without seeing the content of the actual requirements, it is hard to comment on whether the categorizations make sense. ReliabilityFirst suggests removing the categorization of SPS’s from the definition and referencing them in the forthcoming standard(s). 2. If the categorization of SPS section remains within the definition, under the “Aggregate resource loss (tripping or runback of generation or HVdc) greater than the largest Real Power resource within the interconnection”, ReliabilityFirst recommends referencing “nameplate” Real Power resource consistent with the BES definition language.

Individual

Andrew Z. Pusztai

American Transmission Company, LLC

No

The proposed definition has an exclusion of locally sensed and locally operated series and shunt reactive power devices and also includes FACTS devices. ATC has a back-to-back HVDC facility with a locally sensed and locally operated control system for the series real and reactive power device that could quickly change real and/or reactive power flow. However, all auditors may not consider ATC’s HVDC device to be a FACTS device and it is a series device that also controls real power flow. ATC recommends that the SDT consider revising the (d) exclusion text as follows: “Locally sensed and locally operated series and/or shunt devices that control real and/or reactive power, FACTS devices .

Yes

Group

Florida Municipal Power Agency

Frank Gaffney

No

FMPA appreciates the efforts of the team and believes the definition is a significant improvement over the former definition. There are only a few comments we are making in response to this and the next two questions First is that we are of the opinion that Special Protection Systems are indeed Protection Systems as defined in the NERC Glossary, and as applicable to PRC-005-2 recently approved by FERC. The Applicability Section of PRC-005-2 at 4.2.4 reads: "Protection Systems installed as a Special Protection System (SPS) for BES reliability." If an SPS is not a Protection System, then what is the scope of testing required in PRC-005-2 for an SPS? If an SPS is not a Protection System, should the scope of the SAR be changed to include modifications to PRC-005-2? The SDT seems to depend on: "... SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment" in expressing its opinion that SPSs are not Protection Systems; however, those terms are not used in the Glossary definition of Protection Systems. There is nothing in the definition of Protection System that would eliminate SPSs from being a subset of Protection Systems. In addition, under the section "Voltage Threshold" of the paper that includes the proposed definition, the paper states: "(a)ll elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements." If the SPS is not a Protection System that includes: (i) relays; (ii) communication systems; (iii) voltage and current sensing devices; (iv) dc supply; and (v) control circuits as elements of the Protection System, then to what does "all elements" refer?

No

The definition should not include brightlines. Brightlines already exist in at least two standards that would just cause confusion over what brightline to use. The CIP-002-5 standard has a Medium Risk brightline criteria 2.9 of Attachment 1 to CIP-002-5 which states: "2.9. Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable." IRO-005, R9 uses a criteria of: "... a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) ..." Adding another set of brightlines (for no apparent purpose contained within the standards but presumably for the convenience of three of the Regions) that conflict with these brightlines already within the standards will only bring confusion. Brightlines for SPSs should be within each standard, not within the definition. If the SDT does not agree, then, at minimum, the SAR should be changed to modify CIP-002-5 and IRO-005 to align with the newly proposed brightlines. The definition is exceptionally long. By removing the categories and brightlines from the definition, it cuts the definition roughly in half.

The definition does not address automatic actions taken by an EMS, SCADA or DCS and whether that would be considered an SPS. For instance, an EMS can be programmed to perform automated switching (without human intervention) to relieve an overloaded Facility



in a similar manner to an SPS designed with relays or a programmable logic controller. Would such automation cause the EMS to be an SPS and subject to PRC-005-2 requirements for testing?

Individual

John Pearson

ISO New England

No

The first paragraph reads as follows: A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading. Comment: "Cascading" is the result of either the loss of two or more elements or an extreme event, rather than the cause. Therefore, we think the word "cascading" should be deleted from the first paragraph. Also, as currently written, the definition seems to imply that an SPS cannot be used to address the loss of a single element. To avoid this, we think that the definition should be revised to reference NERC Reliability Standards. For instance, the definition could state that an SPS is a scheme designed . . . "to meet system performance requirements identified in NERC Reliability Standards or to limit the impact of an extreme event." The second paragraph reads as follows: Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration. Comment: We think that the first sentence in the second paragraph could be simplified to read "SPS schemes are designed to address reliability concerns such as maintaining acceptable voltages, power flows and system stability." Comments on Exclusions from Definition of SPS: Comments are listed below following the description of schemes that do not constitute an SPS: b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature Comment: We think that exclusion b) is too broad. There are instances where an overcurrent device that opens a line is an SPS. As written currently, these schemes would fall under exclusion b) and would no longer be considered SPSs. In addition, the word "locally" should be changed to "local". Moreover, what is "local" has not been defined and, with technologies such as SmartWire emerging, it is unclear whether or not the controls for such a system would be considered "local." Similarly, some devices like SVCs, STATCOMs, or HVDC terminals also control capacitors at the same station and at surrounding substations. It is unclear whether the definition would classify any of these schemes as an SPS. d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers Comment: We think that generator governors and AGC control should be added to exclusion d). The comment above in exclusion

b) regarding the use of the word “local” instead of “locally” and defining what “local” means also applies to exclusion d). e) Schemes that prevent high line voltage by automatically switching the affected line Comment: While we agree with exclusion f), we think that the Drafting Team should delete exclusion e) as those schemes should be considered an SPS. Additional Exclusion: Comment: Another exclusion “n)” should be added to exclude load throwover schemes from being considered an SPS.

No

The standard reads as follows: SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards. • Type PS (planning-significant): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have a significant impact on the BES. • Type PL (planning-limited): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have only a limited impact on the BES. • Type ES (extreme-significant): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have a significant impact on the BES. • Type EL (extreme-limited): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have only a limited impact on the BES. Comments: The proposed types should match the contingency categories under the TPL standards (current and new). a. For the PS and PL types, change “A scheme designed to meet system performance requirements identified in the NERC Reliability Standards,...” to “A scheme designed to meet system performance requirements identified in NERC Reliability Standard TPL-001-4 Table 1 – Steady State & Stability Performance Planning Events,...” b. Type ES and EL: Referencing the loss of two or more elements seems to mix what are currently Category C events with Category D events. We think this is inappropriate. Instead, for the ES and EL types, change “A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading,...” to “A scheme designed to limit the impact of an extreme event(s) identified in NERC Reliability Standard TPL-001-4 Table 1 – Steady State & Stability Performance Extreme Events, or Cascading,...”. In addition, “Cascading” is the result of either the loss of two or more elements or an extreme event, rather than the cause. Therefore, we think “cascading” should be deleted.

The significant impact language in the standard reads as follows: An SPS is classified as having a significant impact on the BES if failure or inadvertent operation of the scheme results in any of the following: • Non-Consequential Load Loss  $\geq 300$  MW • Aggregate resource loss (tripping or runback of generation or HVdc)  $>$  the largest Real Power resource within the interconnection<sup>4</sup> • Loss of synchronism between two or more portions of the system each including more than one generating plant • Negatively damped oscillations If none of these criteria are met, the SPS is classified as having a limited impact on the BES. <sup>4</sup> I.e., Eastern, Western, ERCOT, or Quebec Interconnection. Comments: a. The term “largest Real Power resource” has not been defined and could lead to confusion. The term could be interpreted to mean the single largest generator or the total of all generators at a site. It is also unclear

whether the term would include an HVDC terminal from another interconnection. There may be a risk that retirement of the largest resource could result in a reclassification of numerous schemes as SPS across the interconnection. Furthermore, the loss of a resource of this size may be manageable in one area, but extremely severe in another, due to differing system characteristics within the same interconnection. The largest power resource should be defined by the area Balancing Authority instead of a continent-wide standard. b. Loss of synchronism between two or more portions of the system each including one or more generating plant: this language is unclear. It could be read to mean that losing a 50 MW load with two 20 MW generators is significant, when in reality it is not. c. Negatively damped oscillations: as written, this could mean a single 20 MW generator, which would not have an impact on the Eastern Interconnection. We think the language should be clarified to reference oscillations that impact a Reliability Coordinator area or a Balancing Authority area.

Individual

Cheryl Moseley

Electric Reliability Council of Texas, Inc.

No

Load side rollover schemes for distribution systems are not clearly identified as exclusions.

No

The distinction between “planning-limited” and “extreme-limited” is not clearly defined in either the definition itself or supporting documentation. NERC Reliability TPL standards include performance requirements to identify “the impact of two or more elements removed, an extreme event, or Cascading.” It could be better to categorize SPSs as “extreme-” or “planning-” on the basis the scheme is mitigating a specific system conditions identified in the TPL standards (i.e. Category B, Category C or Category D) as part of the new SPS definition or as part of supporting documentation. Incorporating this information would ensure continuity with existing standards.

In the definition it is not clearly defined whether series reactor insertion to change system flow should be determined as a special protection system.

Individual

Amy Casuscelli

Xcel Energy Inc.

No

The reliability drivers for SPS may potentially be more than “meet system performance requirements” and “limit the impact of an extreme event” that are acknowledged in the proposed definition. One significant reliability driver that must be included in the definition is prevention of equipment damage – note that SPS may be conceived and installed to prevent equipment damage caused not only by thermal overload, but also due to undesirable phenomenon such as sub-synchronous resonance, loss of effectively grounding in a station, etc.

No

The four proposed types appear to derive from the four possible combinations that can result based on the contingency event classification in the new TPL-001-4 standard (Planning vs Extreme Events) plus the Limited vs Significant Impact criteria provided in the proposed definition. The type PS and type PL generally correspond to the existing classification of Wide-area RAS and Local-area RAS within WECC, and type ES generally corresponds to the existing “safety-net” RAS classification in WECC. These three types also align with the existing SPS classification in NPCC and ERCOT. Although types PS, PL and ES fulfill a reasonable need for differentiation, the technical rationale for needing type EL is not clear. It appears that type EL is simply an extraneous by-product of the classification paradigm used, and can be eliminated due to the following reasons: (i) Does not correspond to any of the existing 3 types in WECC, NPCC or ERCOT, and none of these regions have found their existing classification to be inadequate; (ii) Extreme-Limited is an oxymoron – if an extreme contingency event produces a limited impact, then why should it be characterized as an extreme event? In fact, this awkwardness is already reflected in the Type EL definition – if the “failure or inadvertent operation of the scheme can have only a limited impact on the BES” then why should “a scheme designed to limit the impact” be needed at all?

Suggest revisiting the criteria for significant impact in the proposed definition – the 300 MW load loss threshold may correspond to limited impact in a major load center, and an aggregate resource loss marginally greater than the largest generating unit in the interconnection may not be significant enough if it does not produce any Adverse Reliability Impact in the BES. Perhaps these two criteria also need a better rationale to explain why the proposed thresholds would result in significant \*adverse\* impact on BES reliability.

Group

Colorado Springs Utilities

Kaleb Brimhall

No

Thank you teammates for your work on this definition! Developing a comprehensive list of exclusions is not a reasonable expectation and will lead to problems in the future as more potential exclusions are identified or technological advances are made that are not included in the list. The definition needs to clearly identify what an SPS is without a long list of exclusions. This also creates the problem of including everything that is not excluded. Below is an attempt to try and start down that road, but does not compensate for all the proposed exceptions. A scheme, other than those specifically controlled by other NERC standards, designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of fault within a single protection zone or for the protection of elements for other than fault conditions, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

No

Please further explain why we are categorizing SPS, as we believe that this will lead to further confusion and requests for clarification.

None

Individual

Christina Conway

Oncor Electric Delivery Company LLC

Yes

Oncor agrees with the proposed SPS definition and encourages the SDT to keep the following in the exclusions; Static Var Compensators (SVCs), Series/Shunt Capacitors, and Series/Shunt Reactors. Oncor believes these devices, as used today, are part of “standard” business practice.

Yes

As stated on page 5 of the proposed SPS definition, “SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards”. Oncor encourages that the different types/categories of SPS be subject to applicable requirements.

Individual

Keith Morisette

Tacoma Power

No

Tacoma Power suggests additional clarification seems necessary for (b): “Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature.” Perhaps there could be another category for backing-up operator response and re-dispatch: “Locally sensing devices intended to mitigate thermal damage, within expected system re-dispatch response times, such as 10 minutes or greater. Examples are cooling fans, oil pumps, or thermal protection systems.”

Yes

In the proposed definition, it seems that ‘interconnection’ should be capitalized.

Group

Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing

Wayne Johnson

No

Combining (1) the statement "Use of protection system (lower case) within the SPS definition identifies that SPS are not Protection Systems. " (from page 1 of the SPS Definition document) with (2) "Special Protection System (SPS): A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading. Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include, but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration." (which is the proposed SPS definition from page 4 of the SPS Definition document), ... the schemes being described are more appropriately termed control systems rather than protection systems. If they are not Protection Systems, they should not be called protection systems. We question if there should even be a defined Special Protection Scheme if it is only used through controls to keep the system stable. A definition requiring two pages of notes and clarifications is not an effective definition.

No

What benefit is this categorization to the analysis of the correct operation of these types of protection systems? It is not clear that this distinction is needed for the evaluation of and minimization of recurrence of misoperations of these systems. The classification is unnecessary with respect to the reliability goal. The classification of the type of SPS should only be included in the definition if it is needed for establishing different requirements based on classification - otherwise, it is unneeded.

No other comments

Individual

Scott Langston

City of Tallahassee

Yes

No

It would be beneficial to entities maintaining SPS systems to have a readily available resource on the NERC website that provides guidance to entities on identifying the largest Real Power Source for the interconnection. More description of "negatively damped oscillations" is necessary to determine the scope of what the proposed language includes.

Individual

Ayesha Sabouba

Hydro One

Yes

We do note that the SPS definition excludes what is traditionally considered to be “protection systems.” However, the existing NERC definition for Protection System does not exclude Special Protection Systems. This creates a problem for NERC. We recommend concurrently with this new SPS definition to modify the definition for Protection System to specifically exclude Special Protection Systems. Without doing so would create potential compliance conflicts.

The type classifications need to be clarified and made consistent. For example, “two or more elements removed” can refer to TPL Planning Events P3, P4, P5, P6, and P7. By definition within the TPL Reliability Standard, these are NOT extreme events, but indeed are performance requirements. The proposed change makes the typing of a SPS clear and consistent with existing NERC Reliability Standards. To this end, suggest the following: For the PS and PL types, suggest changing “A scheme designed to meet system performance requirements identified in the NERC Reliability Standards,...” to “A scheme designed to meet system performance requirements identified in NERC Reliability Standard TPL-001-4 Table 1 – Steady State & Stability Performance Planning Events,...” For the ES and EL types, suggest changing “A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading,...” to “A scheme designed to limit the impact of an extreme event(s) identified in NERC Reliability Standard TPL-001-4 Table 1 – Steady State & Stability Performance Extreme Events, or Cascading,...”

Individual

Brett Holland

Kansas City Power & Light

Yes

Yes

Throughout the proposed definition, the term used is scheme. I agree that the use of the term scheme is correct for the types of actions to which the definition applies. I think that the Western Interconnect has the right description with Remedial Action Scheme. The use of the description Special Protection System has the potential to confuse.

Group

Bonneville Power Administration

Andrea Jessup

No

BPA feels the proposed definition appears to clarify what a Special Protection System “is not.” The list of exclusions is extensive. To be more effective, BPA feels the definition should define and clarify what a Special Protection System “is.” To avoid confusion with other protection systems, BPA suggests that the drafting team consider revising the term “Special Protection

System” to “Remedial Action Scheme.” Since an SPS takes specific action in response to either a contingency or specific system response, an SPS is more appropriately defined as a scheme (a systematic plan of action), rather than a system (a functionally related group of elements). The first sentence of the definition states, “A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, and extreme event, or Cascading.” When two or more elements are removed, extreme events, and Cascading are addressed in the NERC Reliability Standards. Therefore, the second part of the sentence “or to limit the impact of two or more elements removed, and extreme event, or Cascading” becomes redundant and should be removed.

No

BPA does not agree with categorizing SPS into the four proposed types. With regard to category types “PS” and “PL,” BPA feels that the terms “wide” or “local” rather than “significant” or “limited” are more descriptive of the geographical impact to the transmission system. In addition, BPA feels the term “planning” suggests there is a distinction between planning and operations use of schemes and suggests not using this type of descriptor. With regard to category types “ES” and “EL”, BPA suggests these be combined and renamed (e.g., safety net) to better reflect their purpose. Since the purpose of these two categories is minimizing the impact of extreme events and not to meet required performance for NERC Category A, B, and C contingencies, BPA feels there isn’t a need to distinguish two levels for ES and EL in a Standard.

The terms “misoperation” and “failure to operate” are both included under the definition for Misoperation in the report “SPS and RAS: Assessment of Definition, Regional Practices, and Application of Related Standards.” BPA feels these terms are two distinct terms and that they are used interchangeably in SPCS/SAMS revised definition. For example, when a scheme “fails to operate,” the result of this has more significant consequences of not meeting system performance for the contingency which requires the scheme to operate. When a scheme “misoperates,” BPA feels this would have a much less significant impact on reliability of the transmission system since the impact is only due to the specific actions taken by the scheme and does not include the contingency. As such, BPA feels these terms need to be separate.

Individual

Richard Vine

California ISO

Yes

No

NERC proposes to categorize SPS (aka RAS) into four major groups, and then apply additional qualifying criteria (e.g. amount of gen or load dropped, etc). This can lead to considerable confusion and inconsistency by various entities on the application of this criteria. A simpler approach should be adopted.



The location of generation in the west (WECC) is often far removed from load sources (which is not nearly as prominent as in the east) and because of this, amounts of generation dropped or curtailed and/or load dropped really has different impacts in the WECC compared to the eastern interconnection. The ISO suggests that a definition for SPS/RAS be added to the "WECC Regional Definitions" section of the NERC Glossary of Terms recognizing the existing WECC classification for SPS/RAS, which is WAPS, LAPS and Safety Net. This will result in three simple categories (as opposed to four) without additional qualifying criteria.

Group

Tucson Electric Power

Bill Darmitzel

No

See comments to questions 2 and 3.

No

Proposed change to definition: Replace "Non-Consequential Load Loss  $\geq$  300 MW" with "Non-Consequential Load Loss  $\geq$  the lesser of load loss equivalent to the largest Real Power resource within the interconnection or the loss of 1000 MW". The 300 MW non-consequential load loss seems arbitrary and does not include technical justification. In keeping with the concept of balancing load and resources, it seems more appropriate to specify non-consequential load loss equivalent to the largest real power resource within the interconnection as was used for the loss of generation. The clauses to define "significant" seem to relate closely to the WECC Peak RC definition of an IROL. On that basis extending the non-consequential load loss to 1000MW is consistent with the IROL definition and is an amount of load that seems appropriate for the interconnected system. Planning Limited and Extreme Limited schemes should meet the IEEE definition of redundancy and not the more severe single component failure requirement appropriate for Planning Significant schemes. Expansion (contingency additions) to a Limited (PL or EL) Special Protection Scheme should trigger a review scheme classification (PL/PS/EL/ES). They should not require a review and approval of the entire Special Protection Scheme. These additions do not change the function of the schematic model and rely on existing design principles in implementation.

Special Protection Schemes currently classified as a Local Area Protection Scheme or Safety Net should be excluded from the proposed Special Protection Scheme definition. These schemes are a local area risk and not a risk to the BES. As such, the requirements for these schemes should be less stringent.

**Additional Comments:**

**IESO**

**Tina Teng**

## **1. YES**

### **Comments:**

We generally agree with the proposed definition, but the phrase “two or more elements removed” in the first paragraph may be confusing since some of the contingencies for meeting performance requirements identified in the NERC Reliability Standards (e.g. the TPL standards) can result in the loss of two elements (e.g. two circuits on the same tower, two elements loss due to breaker failing to operate to clear initial faults, etc.)

We suggest to either remove this phrase (since it’s already covered by the planning assessment or SOL determination requirements or by extreme contingencies), or add a footnote to indicate the exception (i.e., other than those that can be lost due to the contingencies stipulated in the TPL standard).

## **2. NO**

## Proposed Definition of “Remedial Action Scheme”

### *Remedial Action Scheme (RAS)*

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain System stability;
- Maintain acceptable System voltages;
- Maintain acceptable power flows;
- Limit the impact of Cascading; or
- Address other Bulk Electric System (BES) reliability concerns.

These schemes are not Protection Systems; however, they may share components with Protection Systems.

The following do not individually constitute a RAS:

- a. Out-of-step tripping and power swing blocking
- b. Automatic underfrequency load shedding (UFLS) programs
- c. Undervoltage Load Shedding Programs (UVLS Programs)
- d. Autoreclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, tap-changing transformers, or generation excitation, and that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by an operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

## Existing NERC Glossary of Terms Definitions

### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

### *Remedial Action Scheme*

See “Special Protection System”

# Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## Project 2010-05.2 – Special Protection Systems

### Background

The existing NERC Glossary of Terms definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS or RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS or RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. This “broadness,” however, necessitates an exclusion list because without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT is coordinating the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT is introducing a new NERC Glossary term, UVLS Program, to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: “An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.”

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agrees with this assessment and revised the definition of RAS to clarify that it is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally

controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

**Requested Approvals**

Definition of “**Remedial Action Scheme**” and the standards listed below

The following standards are proposed for approval to align the use of RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of “Remedial Action Scheme” becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

The standard numbers below currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

|                |                   |                |
|----------------|-------------------|----------------|
| CIP-002-3(X)   | IRO-005-3.1a(X)   | PRC-017-0(X)   |
| CIP-002-3b(X)  | IRO-014-1(X)      | PRC-020-1(X)   |
| CIP-002-5.1(X) | MOD-029-1a(X)     | PRC-021-1(X)   |
| CIP-003-5(X)   | MOD-030-2(X)      | PRC-023-2(X)   |
| CIP-004-5.1(X) | NUC-001-2.1(X)    | PRC-023-3(X)   |
| CIP-005-5(X)   | PRC-001-1.1(X)    | PRC-024-1(X)   |
| CIP-006-5(X)   | PRC-004-WECC-1(X) | PRC-025-1(X)   |
| CIP-007-5(X)   | PRC-005-2(X)      | TOP-005-2a(X)  |
| CIP-008-5(X)   | PRC-005-3(X)      | TPL-001-0.1(X) |
| CIP-009-5(X)   | PRC-006-1(X)      | TPL-001-4(X)   |
| CIP-010-1(X)   | PRC-012-0(X)      | TPL-002-0b(X)  |
| CIP-011-1(X)   | PRC-013-0(X)      | TPL-003-0b(X)  |
| EOP-004-2(X)   | PRC-014-0(X)      | TPL-004-0a(X)  |
| FAC-010-2.1(X) | PRC-015-0(X)      |                |
| FAC-011-2(X)   | PRC-016-0.1(X)    |                |

**Requested Retirements**

Definition of “**Special Protection System**” and the standards listed below

|             |             |              |
|-------------|-------------|--------------|
| CIP-002-3   | CIP-007-5   | FAC-011-2    |
| CIP-002-3b  | CIP-008-5   | IRO-005-3.1a |
| CIP-002-5.1 | CIP-009-5   | IRO-014-1    |
| CIP-003-5   | CIP-010-1   | MOD-029-1a   |
| CIP-004-5.1 | CIP-011-1   | MOD-030-02   |
| CIP-005-5   | EOP-004-2   | NUC-001-2.1  |
| CIP-006-5   | FAC-010-2.1 | PRC-001-1.1  |

|                |             |             |
|----------------|-------------|-------------|
| PRC-004-WECC-1 | PRC-016-0.1 | TOP-005-2a  |
| PRC-005-2      | PRC-017-0   | TPL-001-0.1 |
| PRC-005-3      | PRC-020-1   | TPL-001-4   |
| PRC-006-1      | PRC-021-1   | TPL-002-0b  |
| PRC-012-0      | PRC-023-2   | TPL-003-0b  |
| PRC-013-0      | PRC-023-3   | TPL-004-0a  |
| PRC-014-0      | PRC-024-1   |             |
| PRC-015-0      | PRC-025-1   |             |

**General Considerations**

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition. This Implementation Plan provides additional time for entities with newly-identified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

**Prerequisite Approvals**

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding  
 Definition of “Undervoltage Load Shedding Program (UVLS Program)” in Project 2008-02 Undervoltage Load Shedding

**Revisions to the NERC Glossary of Terms**

The drafting team proposes the following revised definition:

**Remedial Action Scheme (RAS)**

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives:

- Meet requirements identified in the NERC Reliability Standards;
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- c. Undervoltage Load Shedding Programs (UVLS Programs)



- d. Autoreclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, tap-changing transformers, or generation excitation, and that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by an operator
- l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

### **Conforming Changes to Other Standards**

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

### **Effective Date for Revised Reliability Standards and Definition**

The revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**Implementation Plan for Newly-Identified RAS**

Entities with newly-identified RAS resulting from the application of the definition must be fully compliant with all Reliability Standards applicable to the revised definition of “Remedial Action Scheme” twenty-four (24) months from the Effective Date of the revised definition of “Remedial Action Scheme.” This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

**Retirement of Existing Standards and Definitions**

The requested Reliability Standards for retirement, the current definition of “Special Protection System,” and the current definition of “Remedial Action Scheme” shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of “Remedial Action Scheme” in the particular jurisdiction in which the revised definition is becoming effective.

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(X)
3. **Purpose:** NERC Standards CIP-002-3(X) through CIP-009-3(X) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

**B. Requirements**

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
  - R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
  - R1.2.** The risk-based assessment shall consider the following assets:
    - R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
    - R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
    - R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
    - R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
    - R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
    - R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
    - R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
  - R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
  - R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
  - R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of

the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

- 1.5.1** None.

**2. Violation Severity Levels (To be developed later.)**

**E. Regional Variances**

None identified.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2       |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3       |                   | Updated version number from -2 to -3  |  |
| 3       | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
| 3(X)    | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(X)
3. **Purpose:** NERC Standards CIP-002-3(X) through CIP-009-3(X) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

## B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of



the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

- 1.5.1** None.

**2. Violation Severity Levels (To be developed later.)**

**E. Regional Variances**

None identified.

**Version History**

| Version     | Date              | Action  | Change Tracking   |
|-------------|-------------------|---|---|
| 1           | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata  |
| 2           |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3           |                   | Updated version number from -2 to -3  |   |
| 3           | December 16, 2009 | Approved by the NERC Board of Trustees  | Update  |
| <u>3(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3b(X)
3. **Purpose:** NERC Standards CIP-002-3b(X) through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3b(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3b(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3b(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

## B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3b(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.

- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

Compliance Audits  
Self-Certifications  
Spot Checking  
Compliance Violation Investigations  
Self-Reporting  
Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3b(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

**1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

**1.5.1** None.

2. Violation Severity Levels

| Requirement | VRF    | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-------------|--------|-----------|---|---|--|
| R1.         | MEDIUM | N/A       | N/A   | N/A   | The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.                 |
| R1.1.       | LOWER  | N/A       | The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures. | The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria. | The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria. |
| R1.2.       | MEDIUM | N/A       | N/A   | N/A   | The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.                             |
| R1.2.1.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.2.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.3.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.4.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.5.     | LOWER  | N/A       | N/A   | N/A   | N/A  |

**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

| Requirement | VRF   | Lower VSL | Moderate VSL  | High VSL   | Severe VSL   |
|-------------|-------|-----------|---|--|--|
| R1.2.6.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R1.2.7.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R2.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.  | The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.   |
| R3.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required. | The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null. |
| R3.1.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.2.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.3.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R4.         | LOWER | N/A       | The Responsible Entity does not have a signed and dated | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual   | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of   |



**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

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| Requirement | VRF | Lower VSL | Moderate VSL   | High VSL   | Severe VSL  |
|-------------|-----|-----------|--|--|---|
|             |     |           | record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets <b>or</b> the list of Critical Cyber Assets (even if such lists are null.) | approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.) | 1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.) |

**E. Regional Variances**

None identified.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2       |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3       |                   | Updated version number from -2 to -3  |  |
| 3       | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
| 3a      | May 9, 2012       | Interpretation of R3 for Duke Energy adopted by the NERC Board of Trustees  |  |
| 3b      | February 7, 2013  | Interpretation of R1.2.5 for OGE adopted by the NERC Board of Trustees  |  |
| 3b      | March 21, 2013    | FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)  |  |
| 3b(X)   | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Appendix 1

**Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation**

Date submitted: 2/24/11

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

**Requirement Number and Text of Requirement**

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

**Identify specifically what requirement needs clarification (as submitted):**

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

### **Question Summary**

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

### **Response**

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3b(X)
3. **Purpose:** NERC Standards CIP-002-3b(X) through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3b(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3b(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3b(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

## B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** ~~Special Protection System~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3b(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.

- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3b(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

**1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

**1.5.1** None.



2. Violation Severity Levels

| Requirement | VRF    | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-------------|--------|-----------|---|---|--|
| R1.         | MEDIUM | N/A       | N/A   | N/A   | The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.                 |
| R1.1.       | LOWER  | N/A       | The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures. | The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria. | The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria. |
| R1.2.       | MEDIUM | N/A       | N/A   | N/A   | The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.                             |
| R1.2.1.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.2.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.3.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.4.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.5.     | LOWER  | N/A       | N/A   | N/A   | N/A  |

| Requirement | VRF   | Lower VSL | Moderate VSL  | High VSL   | Severe VSL   |
|-------------|-------|-----------|---|--|--|
| R1.2.6.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R1.2.7.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R2.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.  | The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.   |
| R3.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required. | The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null. |
| R3.1.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.2.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.3.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R4.         | LOWER | N/A       | The Responsible Entity does not have a signed and dated | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual   | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of   |

**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

| Requirement | VRF | Lower VSL | Moderate VSL   | High VSL   | Severe VSL  |
|-------------|-----|-----------|--|--|---|
|             |     |           | record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets <b>or</b> the list of Critical Cyber Assets (even if such lists are null.) | approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.) | 1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.) |

**E. Regional Variances**

None identified.

**Version History**

| Version             | Date              | Action  | Change Tracking   |
|---------------------|-------------------|---|---|
| 1                   | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata  |
| 2                   |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3                   |                   | Updated version number from -2 to -3  |   |
| 3                   | December 16, 2009 | Approved by the NERC Board of Trustees  | Update  |
| 3a                  | May 9, 2012       | Interpretation of R3 for Duke Energy adopted by the NERC Board of Trustees  |   |
| 3b                  | February 7, 2013  | Interpretation of R1.2.5 for OGE adopted by the NERC Board of Trustees  |   |
| 3b                  | March 21, 2013    | FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)  |   |
| <del>3b</del> 3b(X) | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## Appendix 1

### Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation

Date submitted: 2/24/11

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

#### Requirement Number and Text of Requirement

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

#### Identify specifically what requirement needs clarification (as submitted):

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

### **Question Summary**

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

### **Response**

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

## A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-5.1(X)
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1. **Balancing Authority**
    - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
        - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3. **Generator Operator**
    - 4.1.4. **Generator Owner**
    - 4.1.5. **Interchange Coordinator or Interchange Authority**

**4.1.6. Reliability Coordinator**

**4.1.7. Transmission Operator**

**4.1.8. Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1. Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1.** Each UFLS or UVLS System that:

**4.2.1.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2.** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3. Exemptions:** The following are exempt from Standard CIP-002-5.1(X):

**4.2.3.1.** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.



**4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-002-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required CIP-002-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

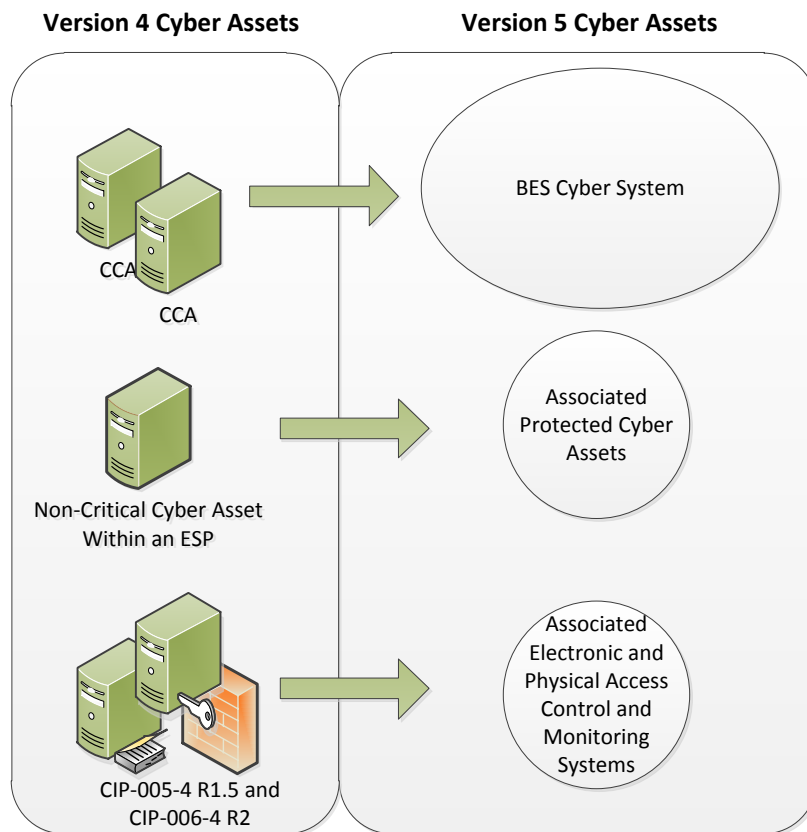
This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**BES Cyber Systems**

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and

scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

### **Reliable Operation of the BES**

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

### **Real-time Operations**

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

### **Categorization Criteria**

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

### **Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems**

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

**Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

**Physical Access Control Systems (“PACS”)**– Examples include: authentication servers, card systems, and badge control systems.

**Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

## B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [*Violation Risk Factor: High*][*Time Horizon: Operations Planning*]
- i.** Control Centers and backup Control Centers;
  - ii.** Transmission stations and substations;
  - iii.** Generation resources;
  - iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
  - v.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
  - vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
  - 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
  - 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

**R2.** The Responsible Entity shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
- 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

**M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

- None

2. Table of Compliance Elements

| R # | Time Horizon        | VRF  | Violation Severity Levels (CIP-002-5.1(X))  |  |  |   |
|-----|---------------------|------|---|--|--|---|
|     |                     |      | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
| R1  | Operations Planning | High | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-5.1(X))   |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> | <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p> | <p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p> | <p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-5.1(X))   |  |  |   |
|-----|--------------|-----|--|--|--|---|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|     |              |     | <p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p> | <p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p> | <p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p> | <p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p> |

| R #       | Time Horizon               | VRF          | Violation Severity Levels (CIP-002-5.1(X))  |   |   |   |
|-----------|----------------------------|--------------|---|---|---|---|
|           |                            |              | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Lower</b> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p> |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## **CIP-002-5.1(X) - Attachment 1**

### **Impact Rating Criteria**

*The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.*

#### **1. High Impact Rating (H)**

Each BES Cyber System used by and located at any of the following:

- 1.1.** Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2.** Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4.** Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

#### **2. Medium Impact Rating (M)**

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1.** Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2.** Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

| Voltage Value of a Line           | Weight Value per Line |
|-----------------------------------|-----------------------|
| less than 200 kV (not applicable) | (not applicable)      |
| 200 kV to 299 kV                  | 700                   |
| 300 kV to 499 kV                  | 1300                  |
| 500 kV and above                  | 0                     |

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.
- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

### **3. Low Impact Rating (L)**

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1(X) and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1(X). This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

#### **CIP-002-5.1(X)**

CIP-002-5.1(X) requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber

Systems that would be subject to CIP-002-5.1(X). The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

| Entity Registration         | RC | BA | TOP | TO | DP | GOP | GO |
|-----------------------------|----|----|-----|----|----|-----|----|
| Dynamic Response            |    | X  | X   | X  | X  | X   | X  |
| Balancing Load & Generation | X  | X  | X   | X  | X  | X   | X  |
| Controlling Frequency       |    | X  |     |    |    | X   | X  |
| Controlling Voltage         |    |    | X   | X  | X  |     | X  |
| Managing Constraints        | X  |    | X   |    |    | X   |    |
| Monitoring and Control      |    |    | X   |    |    | X   |    |
| Restoration                 |    |    | X   |    |    | X   |    |
| Situation Awareness         | X  | X  | X   |    |    | X   |    |
| Inter-Entity coordination   | X  | X  | X   | X  |    | X   | X  |

**Dynamic Response**

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:



- Spinning reserves (contingency reserves)
  - Providing actual reserve generation when called upon (GO,GOP)
  - Monitoring that reserves are sufficient (BA)
- Governor Response
  - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
  - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
  - Zone protection for breaker failure (DP, TO, TOP)
  - Breaker protection (DP, TO, TOP)
  - Current, frequency, speed, phase (TO, TOP, GO, GOP)
- Remedial Action Schemes
  - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

### **Balancing Load and Generation**

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
  - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
  - Software used to perform calculation (BA)
- Demand Response
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)
- Manually Initiated Load shedding
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)

- Non-spinning reserve (contingency reserve)
  - Know generation status, capability, ramp rate, start time (GO, BA)
  - Start units and provide energy (GOP)

### **Controlling Frequency (Real Power)**

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
  - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
  - Software to calculate unit adjustments (BA)
  - Transmit adjustments to individual units (GOP)
  - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
  - Frequency source, schedule (BA)
  - Governor control system (GO)

### **Controlling Voltage (Reactive Power)**

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)
- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

### **Managing Constraints**

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

### **Monitoring and Control**

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
  - SCADA (TOP, GOP)
  - Substation automation (TOP)

### **Restoration of BES**

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
  - Through black start units (TOP, GOP)
  - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

### **Situational Awareness**

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

### **Inter-Entity Coordination**

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

### **Applicability to Distribution Providers**

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

### **Requirement R1:**

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

## **Attachment 1**

### **Overall Application**

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1(X), these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.
- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

### **High Impact Rating (H)**

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some

of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

### **Medium Impact Rating (M)**

#### **Generation**

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

### Transmission

*The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.*

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.



It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
  - Excluded radial facilities that would only provide support for single generation facilities.
  - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC’s document “[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)”, Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting “other Transmission stations or substations” determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate

connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaAR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.
- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

### **Low Impact Rating (L)**

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

### **Restoration Facilities**

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

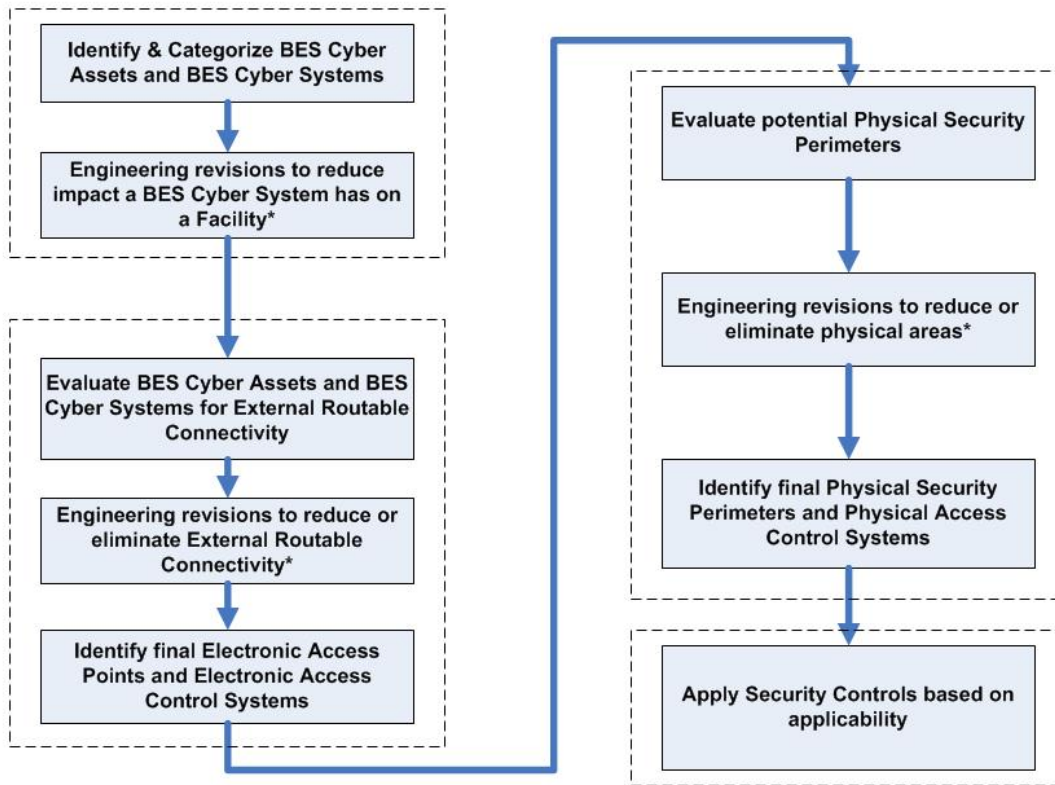
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

### Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

### Overview (Generation Facility)



\* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

**Rationale:**

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

**Rationale for R1:**

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

**Rationale for R2:**

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

**Version History**

| Version | Date     | Action  | Change Tracking |
|---------|----------|---|-----------------|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”   | 3/24/06         |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a Responsible Entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |                 |
| 3       | 12/16/09 | Updated version number from -2 to -3.   | Update          |

Guidelines and Technical Basis

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|        |          |   |  |
|--------|----------|---|--|
|        |          | Approved by the NERC Board of Trustees.                                       |  |
| 3      | 3/31/10  | Approved by FERC.   |  |
| 4      | 12/30/10 | Modified to add specific criteria for Critical Asset identification.          | Update   |
| 4      | 1/24/11  | Approved by the NERC Board of Trustees.                                       | Update   |
| 5      | 11/26/12 | Adopted by the NERC Board of Trustees.  | Modified to coordinate with other CIP standards and to revise format to use RBS Template.    |
| 5.1    | 9/30/13  | Replaced "Devices" with "Systems" in a definition in background section.      | Errata   |
| 5.1    | 11/22/13 | FERC Order issued approving CIP-002-5.1. (Order becomes effective on 2/3/14.) |  |
| 5.1(X) | TBD      | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-5.1(X)
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1. **Balancing Authority**
    - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
        - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3. **Generator Operator**
    - 4.1.4. **Generator Owner**

**4.1.5. Interchange Coordinator or Interchange Authority**

**4.1.6. Reliability Coordinator**

**4.1.7. Transmission Operator**

**4.1.8. Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1. Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1.** Each UFLS or UVLS System that:

**4.2.1.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2.** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3. Exemptions:** The following are exempt from Standard CIP-002-5.1(X):

**4.2.3.1.** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-002-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required CIP-002-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

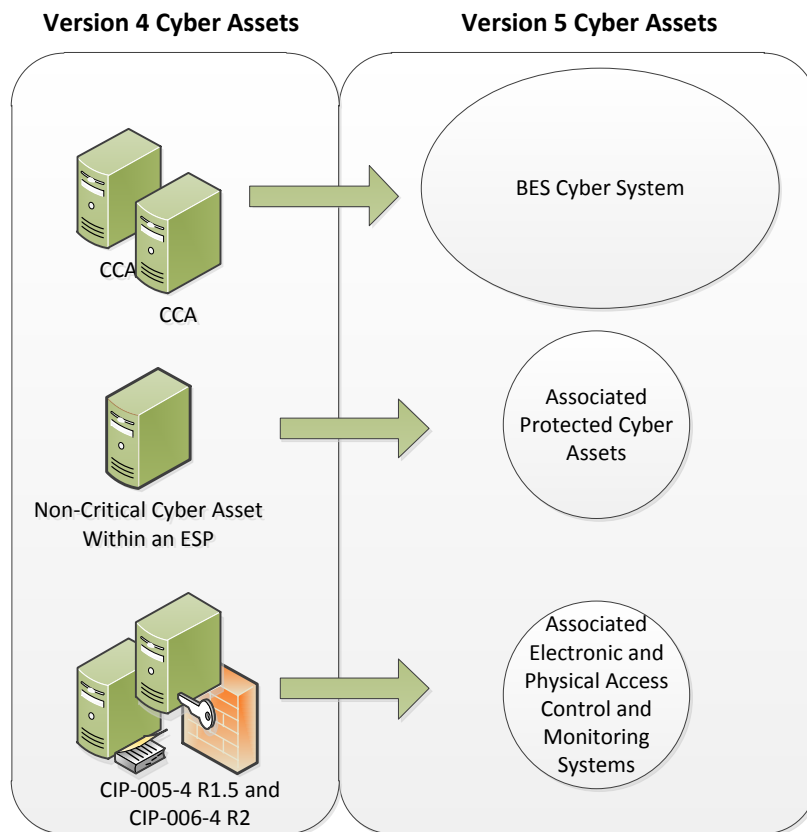
This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**BES Cyber Systems**

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and

scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

### **Reliable Operation of the BES**

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

### **Real-time Operations**

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

### **Categorization Criteria**

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

### **Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems**

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

**Electronic Access Control or Monitoring Systems (“EACMS”)** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

**Physical Access Control Systems (“PACS”)**– Examples include: authentication servers, card systems, and badge control systems.

**Protected Cyber Assets (“PCA”)** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

## B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [*Violation Risk Factor: High*][*Time Horizon: Operations Planning*]
- i. Control Centers and backup Control Centers;
  - ii. Transmission stations and substations;
  - iii. Generation resources;
  - iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
  - v. ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
  - vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
  - 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
  - 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

**R2.** The Responsible Entity shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
- 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

**M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

- None



2. Table of Compliance Elements

| R # | Time Horizon        | VRF  | Violation Severity Levels (CIP-002-5.1(X))  |  |  |   |
|-----|---------------------|------|---|--|--|---|
|     |                     |      | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
| R1  | Operations Planning | High | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> | <p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-5.1(X))   |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> | <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p> | <p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p> | <p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-5.1(X))   |  |  |   |
|-----|--------------|-----|--|--|--|---|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|     |              |     | <p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p> | <p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p> | <p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p> | <p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p> |

| R #       | Time Horizon               | VRF          | Violation Severity Levels (CIP-002-5.1(X))  |   |   |   |
|-----------|----------------------------|--------------|---|---|---|---|
|           |                            |              | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Lower</b> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p> | <p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p> |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## CIP-002-5.1(X) - Attachment 1

### Impact Rating Criteria

*The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.*

#### 1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

- 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4. Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

#### 2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

| Voltage Value of a Line           | Weight Value per Line |
|-----------------------------------|-----------------------|
| less than 200 kV (not applicable) | (not applicable)      |
| 200 kV to 299 kV                  | 700                   |
| 300 kV to 499 kV                  | 1300                  |
| 500 kV and above                  | 0                     |

- 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.
- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

### **3. Low Impact Rating (L)**

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.



## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1(X) and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1(X). This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

#### **CIP-002-5.1(X)**

CIP-002-5.1(X) requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber

Systems that would be subject to CIP-002-5.1(X). The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

| Entity Registration         | RC | BA | TOP | TO | DP | GOP | GO |
|-----------------------------|----|----|-----|----|----|-----|----|
| Dynamic Response            |    | X  | X   | X  | X  | X   | X  |
| Balancing Load & Generation | X  | X  | X   | X  | X  | X   | X  |
| Controlling Frequency       |    | X  |     |    |    | X   | X  |
| Controlling Voltage         |    |    | X   | X  | X  |     | X  |
| Managing Constraints        | X  |    | X   |    |    | X   |    |
| Monitoring and Control      |    |    | X   |    |    | X   |    |
| Restoration                 |    |    | X   |    |    | X   |    |
| Situation Awareness         | X  | X  | X   |    |    | X   |    |
| Inter-Entity coordination   | X  | X  | X   | X  |    | X   | X  |

**Dynamic Response**

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
  - Providing actual reserve generation when called upon (GO,GOP)
  - Monitoring that reserves are sufficient (BA)
- Governor Response
  - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
  - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
  - Zone protection for breaker failure (DP, TO, TOP)
  - Breaker protection (DP, TO, TOP)
  - Current, frequency, speed, phase (TO, TOP, GO, GOP)
- ~~Special Protection Systems or~~ Remedial Action Schemes
  - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

### **Balancing Load and Generation**

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
  - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
  - Software used to perform calculation (BA)
- Demand Response
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)
- Manually Initiated Load shedding
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)

- Non-spinning reserve (contingency reserve)
  - Know generation status, capability, ramp rate, start time (GO, BA)
  - Start units and provide energy (GOP)

### **Controlling Frequency (Real Power)**

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
  - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
  - Software to calculate unit adjustments (BA)
  - Transmit adjustments to individual units (GOP)
  - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
  - Frequency source, schedule (BA)
  - Governor control system (GO)

### **Controlling Voltage (Reactive Power)**

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)
- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

### **Managing Constraints**

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

### **Monitoring and Control**

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
  - SCADA (TOP, GOP)
  - Substation automation (TOP)

### **Restoration of BES**

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
  - Through black start units (TOP, GOP)
  - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

### **Situational Awareness**

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

### **Inter-Entity Coordination**

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

### **Applicability to Distribution Providers**

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

### **Requirement R1:**

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

## **Attachment 1**

### **Overall Application**

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1(X), these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.
- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

### **High Impact Rating (H)**

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some

of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

### **Medium Impact Rating (M)**

#### **Generation**

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.



The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

### Transmission

*The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.*

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
  - Excluded radial facilities that would only provide support for single generation facilities.
  - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC’s document “[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)”, Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting “other Transmission stations or substations” determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate

connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those ~~Special Protection Systems (SPS)~~, Remedial Action Schemes (RAS); or automated switching Systems installed to ensure BES operation within IROs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROs if they fail to operate as designed. By the definition of IRO, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaAR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.
- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

### **Low Impact Rating (L)**

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

### **Restoration Facilities**

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

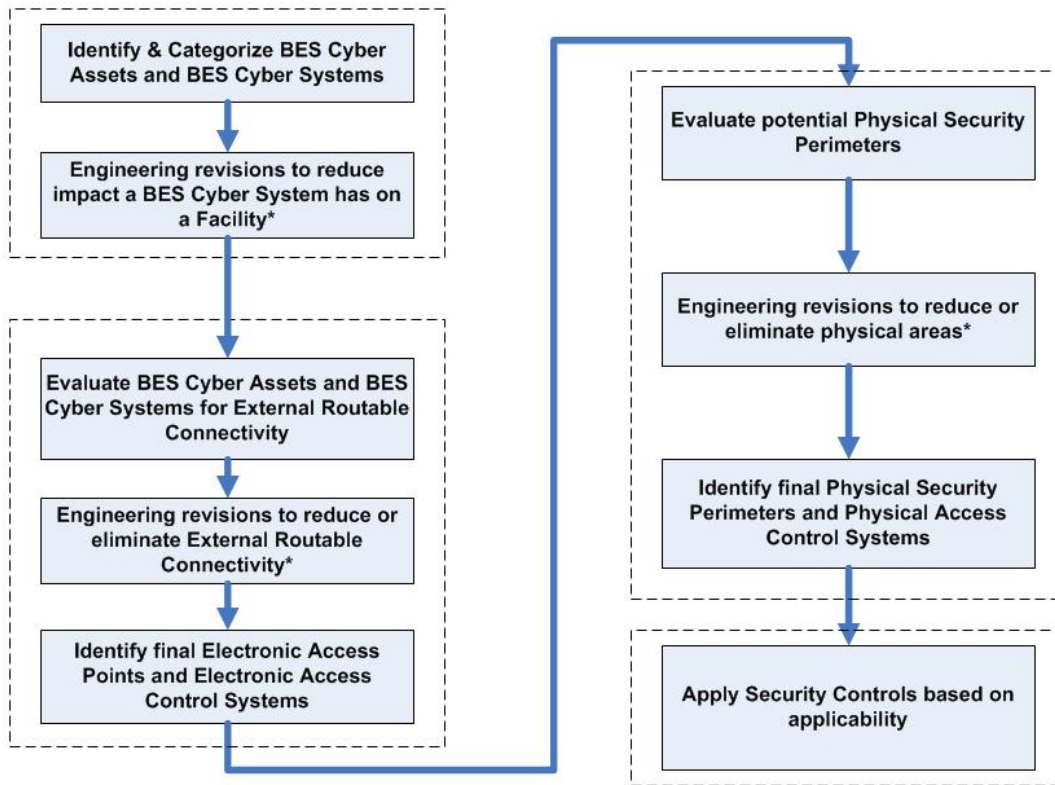
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

### Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

### Overview (Generation Facility)



\* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.



**Rationale:**

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

**Rationale for R1:**

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

**Rationale for R2:**

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

**Version History**

| Version | Date     | Action  | Change Tracking |
|---------|----------|---|-----------------|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”   | 3/24/06         |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority. |                 |
| 3       | 12/16/09 | Updated version number from -2 to -3.   | Update          |

Guidelines and Technical Basis

|               |            |   |   |
|---------------|------------|---|---|
|               |            | Approved by the NERC Board of Trustees.                                       |   |
| 3             | 3/31/10    | Approved by FERC.   |   |
| 4             | 12/30/10   | Modified to add specific criteria for Critical Asset identification.          | Update  |
| 4             | 1/24/11    | Approved by the NERC Board of Trustees.                                       | Update  |
| 5             | 11/26/12   | Adopted by the NERC Board of Trustees.  | Modified to coordinate with other CIP standards and to revise format to use RBS Template.           |
| 5.1           | 9/30/13    | Replaced “Devices” with “Systems” in a definition in background section.      | Errata  |
| 5.1           | 11/22/13   | FERC Order issued approving CIP-002-5.1. (Order becomes effective on 2/3/14.) |   |
| <u>5.1(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>                                  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-5(X)
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**

#### **4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-003-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval. CIP-003-5(X), Requirement R2 shall become effective on the later of July 1, 2016, or the first calendar day of the 13th calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, and CIP-003-5(X), Requirement R2 shall become effective on the first day of the 13th calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

#### 6. **Background:**

Standard CIP-003-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5, CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying "implement" as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements. The documented processes themselves are not required to include the ". . . identifies, assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented

processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

## B. Requirements and Measures

- R1.** Each Responsible Entity, for its high impact and medium impact BES Cyber Systems, shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 1.1** Personnel & training (CIP-004);
  - 1.2** Electronic Security Perimeters (CIP-005) including Interactive Remote Access;
  - 1.3** Physical security of BES Cyber Systems (CIP-006);
  - 1.4** System security management (CIP-007);
  - 1.5** Incident reporting and response planning (CIP-008);
  - 1.6** Recovery plans for BES Cyber Systems (CIP-009);
  - 1.7** Configuration change management and vulnerability assessments (CIP-010);
  - 1.8** Information protection (CIP-011); and
  - 1.9** Declaring and responding to CIP Exceptional Circumstances.
- M1.** Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
- R2.** Each Responsible Entity for its assets identified in CIP-002-5(X), Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Cyber security awareness;
  - 2.2** Physical security controls;
  - 2.3** Electronic access controls for external routable protocol connections and Dial-up Connectivity; and
  - 2.4** Incident response to a Cyber Security Incident.

An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required.

- M2.** Examples of evidence may include, but are not limited to, one or more documented cyber security policies and evidence of processes, procedures, or plans that demonstrate the implementation of the required topics; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
  
- R3.** Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium]*  
*[Time Horizon: Operations Planning]*
  
- M3.** An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.
  
- R4.** The Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower]* *[Time Horizon: Operations Planning]*
  
- M4.** An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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



The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information:**

- None

2. Table of Compliance Elements

| R # | Time Horizon        | VRF    | Violation Severity Levels (CIP-003-5(X))   |  |  |  |
|-----|---------------------|--------|--|--|--|--|
|     |                     |        | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
| R1  | Operations Planning | Medium | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did complete this review</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did complete this review</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1)</p> <p>OR</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-003-5(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>in less than or equal to 16 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of</p> | <p>in less than or equal to 17 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of</p> | <p>calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1)</p> | <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 18 calendar</p> |

| R #       | Time Horizon               | VRF          | Violation Severity Levels (CIP-003-5(X))  |   |  |  |
|-----------|----------------------------|--------------|---|---|--|--|
|           |                            |              | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|           |                            |              | the previous approval. (R1)   | the previous approval. (R1)   |  | months of the previous approval. (R1)  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Lower</b> | <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 but did not identify,</p> | <p>The Responsible Entity did not document or implement any cyber security policies for assets with a low impact rating that address the topics as required by R2. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 18 calendar months of the previous review. (R2)</p> <p>OR</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-003-5(X))  |   |  |  |
|-----|--------------|-----|---|---|--|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|     |              |     | <p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p> | <p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p> | <p>assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to</p> | <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 18 calendar months of the previous approval. (R2)</p> |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-003-5(X))   |  |  |  |
|-----------|----------------------------|---------------|--|--|--|--|
|           |                            |               | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|           |                            |               | approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 15 calendar months but did not complete this approval in less than or equal to 16 calendar months of the previous approval. (R2) | approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 16 calendar months but did not complete this approval in less than or equal to 17 calendar months of the previous approval. (R2) | Requirement R2 within 17 calendar months but did not complete this approval in less than or equal to 18 calendar months of the previous approval. (R2)                             |  |
| <b>R3</b> | <b>Operations Planning</b> | <b>Medium</b> | The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this   | The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did   | The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in | The Responsible Entity has not identified, by name, a CIP Senior Manager.<br><br>OR<br>The Responsible Entity has identified |

| R #       | Time Horizon               | VRF          | Violation Severity Levels (CIP-003-5(X))   |  |   |   |
|-----------|----------------------------|--------------|--|--|---|---|
|           |                            |              | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|           |                            |              | change in less than 40 calendar days of the change. (R3)   | document this change in less than 50 calendar days of the change. (R3)   | less than 60 calendar days of the change. (R3)  | by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)  |
| <b>R4</b> | <b>Operations Planning</b> | <b>Lower</b> | The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4) | The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4) | The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a process to delegate actions from the CIP Senior Manager, and has Identified deficiencies but did not assess or correct the deficiencies.(R4)<br><br>OR<br>The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a | The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4)<br><br>OR<br>The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-003-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | process to delegate actions from the CIP Senior Manager, but did not identify, assess, or correct the deficiencies.(R4)<br><br>OR<br><br>The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4) | not document changes to the delegate within 60 calendar days of the change. (R4) |



**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

The number of policies and their specific language are guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The cyber security policy must cover in sufficient detail the nine topical areas required by CIP-003-5(X), Requirement R1. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R1. Implementation of the cyber security policy is not specifically included in CIP-003-5(X), Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-004 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements from CIP-004 through CIP-011, but rather to put together a holistic cyber security policy appropriate to its organization. The assessment through the Compliance Monitoring and Enforcement Program of policy items that extend beyond the scope of CIP-004 through CIP-011 should not be considered candidates for potential violations. The Responsible Entity should consider the following for each of the required topics in its cyber security policy:

#### 1.1 Personnel & training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

### 1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN “split-tunneling” or “dual-homed” workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity’s Interactive Remote Access controls

### 1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

### 1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

### 1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

### 1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components

- Availability of system backups

### 1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

### 1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

### 1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

The Standard Drafting Team (SDT) has removed requirements relating to exceptions to a Responsible Entity's security policies since it is a general management issue that is not within the scope of a reliability requirement. The SDT considers it to be an internal policy requirement and not a reliability requirement. However, the SDT encourages Responsible Entities to continue this practice as a component of its cyber security policy.

In this and all subsequent required approvals in the NERC CIP Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

#### **Requirement R2:**

As with Requirement R1, the number of policies and their specific language would be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization or as components of specific programs. The cyber security policy must cover in sufficient detail the four topical areas required by CIP-003-5(X), Requirement R2. The Responsible Entity has flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R2. The intent of the requirement is to outline a set of basic protections that all low impact BES Cyber Systems should receive without requiring a significant administrative and compliance overhead. The SDT intends that demonstration of this requirement can be reasonably accomplished through providing evidence of related processes, procedures, or plans. While the audit staff may choose to review an example low impact BES Cyber System, the SDT believes strongly that the current method (as of this writing) of reviewing a statistical sample of systems

is not necessary. The SDT also notes that in topic 2.3, the SDT uses the term “electronic access control” in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing.

### **Requirement R3:**

The intent of CIP-003-5(X), Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that this CIP Senior Manager play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

### **Requirement R4:**

As indicated in the rationale for CIP-003-5(X), Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the Responsible Entity should have significant flexibility to adapt this requirement to their existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records provides a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up to date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

## **Rationale:**

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

### **Rationale for R1:**

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

Annual review and approval of the cyber security policy ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

### **Rationale for R2:**

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

The language in Requirement R2, Part 2.3 “. . . for external routable protocol connections and Dial-up Connectivity . . .” was included to acknowledge the support given in FERC Order 761, paragraph 87, for electronic security perimeter protections “of some form” to be applied to all BES Cyber Systems, regardless of impact. Part 2.3 uses the phrase “external routable protocol connections” instead of the defined term “External Routable Connectivity,” because the latter term has very specific connotations relating to Electronic Security Perimeters and high and medium impact BES Cyber Systems. Using the glossary term “External Routable Connectivity” in the context of Requirement R2 would not be appropriate because Requirement R2 is limited in scope to low impact BES Cyber Systems.

Review and approval of the cyber security policy at least every 15 calendar months ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

**Rationale for R3:**

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the *Glossary of Terms used in NERC Reliability Standards* so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has “the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards” which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the senior manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

**Rationale for R4:**

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

## Version History

| Version | Date     | Action   | Change Tracking   |
|---------|----------|--|---|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”  | 3/24/06   |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3       | 12/16/09 | Updated version number from -2 to -3<br>Approved by the NERC Board of Trustees.  |   |
| 3       | 3/31/10  | Approved by FERC.  |   |
| 4       | 1/24/11  | Approved by the NERC Board of Trustees.  | Update to conform to changes to CIP-002-4 (Project 2008-06)                               |
| 5       | 11/26/12 | Adopted by the NERC Board of Trustees.   | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |
| 5       | 11/22/13 | FERC Order issued approving CIP-003-5. (Order becomes effective 2/3/14.)   |   |
| 5(X)    | TBD      | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial                    |



|  |  |  |                          |
|--|--|--|--------------------------|
|  |  |  | Action Scheme<br>and RAS |
|--|--|--|--------------------------|

## A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-5(X)
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**

**4.1.7 Transmission Operator**

**4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-003-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval. CIP-003-5(X), Requirement R2 shall become effective on the later of July 1, 2016, or the first calendar day of the 13th calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, and CIP-003-5(X), Requirement R2 shall become effective on the first day of the 13th calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-003-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5, CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying "implement" as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements. The documented processes themselves are not required to include the ". . . identifies, assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects

are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

## B. Requirements and Measures

- R1.** Each Responsible Entity, for its high impact and medium impact BES Cyber Systems, shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 1.1** Personnel & training (CIP-004);
  - 1.2** Electronic Security Perimeters (CIP-005) including Interactive Remote Access;
  - 1.3** Physical security of BES Cyber Systems (CIP-006);
  - 1.4** System security management (CIP-007);
  - 1.5** Incident reporting and response planning (CIP-008);
  - 1.6** Recovery plans for BES Cyber Systems (CIP-009);
  - 1.7** Configuration change management and vulnerability assessments (CIP-010);
  - 1.8** Information protection (CIP-011); and
  - 1.9** Declaring and responding to CIP Exceptional Circumstances.
- M1.** Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
- R2.** Each Responsible Entity for its assets identified in CIP-002-5(X), Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Cyber security awareness;
  - 2.2** Physical security controls;
  - 2.3** Electronic access controls for external routable protocol connections and Dial-up Connectivity; and
  - 2.4** Incident response to a Cyber Security Incident.

An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required.

- M2.** Examples of evidence may include, but are not limited to, one or more documented cyber security policies and evidence of processes, procedures, or plans that demonstrate the implementation of the required topics; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
  
- R3.** Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium]*  
*[Time Horizon: Operations Planning]*
  
- M3.** An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.
  
- R4.** The Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower]* *[Time Horizon: Operations Planning]*
  
- M4.** An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information:**

- None



2. Table of Compliance Elements

| R # | Time Horizon        | VRF    | Violation Severity Levels (CIP-003-5(X))   |  |  |  |
|-----|---------------------|--------|--|--|--|--|
|     |                     |        | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
| R1  | Operations Planning | Medium | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did complete this review</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did complete this review</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1)</p> <p>OR</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-003-5(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>in less than or equal to 16 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of</p> | <p>in less than or equal to 17 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of</p> | <p>calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1)</p> | <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 18 calendar</p> |

| R #       | Time Horizon               | VRF          | Violation Severity Levels (CIP-003-5(X))  |   |  |  |
|-----------|----------------------------|--------------|---|---|--|--|
|           |                            |              | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|           |                            |              | the previous approval. (R1)   | the previous approval. (R1)   |  | months of the previous approval. (R1)  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Lower</b> | <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of</p> | <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 but did not identify,</p> | <p>The Responsible Entity did not document or implement any cyber security policies for assets with a low impact rating that address the topics as required by R2. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 18 calendar months of the previous review. (R2)</p> <p>OR</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-003-5(X))  |   |  |  |
|-----|--------------|-----|---|---|--|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|     |              |     | <p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p> | <p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p> | <p>assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to</p> | <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 18 calendar months of the previous approval. (R2)</p> |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-003-5(X))   |  |  |  |
|-----------|----------------------------|---------------|--|--|--|--|
|           |                            |               | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|           |                            |               | approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 15 calendar months but did not complete this approval in less than or equal to 16 calendar months of the previous approval. (R2) | approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 16 calendar months but did not complete this approval in less than or equal to 17 calendar months of the previous approval. (R2) | Requirement R2 within 17 calendar months but did not complete this approval in less than or equal to 18 calendar months of the previous approval. (R2)                             |  |
| <b>R3</b> | <b>Operations Planning</b> | <b>Medium</b> | The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this   | The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did   | The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in | The Responsible Entity has not identified, by name, a CIP Senior Manager.<br><br>OR<br>The Responsible Entity has identified |

| R #       | Time Horizon               | VRF          | Violation Severity Levels (CIP-003-5(X))   |  |   |   |
|-----------|----------------------------|--------------|--|--|---|---|
|           |                            |              | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|           |                            |              | change in less than 40 calendar days of the change. (R3)   | document this change in less than 50 calendar days of the change. (R3)   | less than 60 calendar days of the change. (R3)  | by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)  |
| <b>R4</b> | <b>Operations Planning</b> | <b>Lower</b> | The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4) | The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4) | The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a process to delegate actions from the CIP Senior Manager, and has Identified deficiencies but did not assess or correct the deficiencies.(R4)<br><br>OR<br>The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a | The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4)<br><br>OR<br>The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-003-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | process to delegate actions from the CIP Senior Manager, but did not identify, assess, or correct the deficiencies.(R4)<br><br>OR<br><br>The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4) | not document changes to the delegate within 60 calendar days of the change. (R4) |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.



## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

The number of policies and their specific language are guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The cyber security policy must cover in sufficient detail the nine topical areas required by CIP-003-5(X), Requirement R1. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R1. Implementation of the cyber security policy is not specifically included in CIP-003-5(X), Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-004 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements from CIP-004 through CIP-011, but rather to put together a holistic cyber security policy appropriate to its organization. The assessment through the Compliance Monitoring and Enforcement Program of policy items that extend beyond the scope of CIP-004 through CIP-011 should not be considered candidates for potential violations. The Responsible Entity should consider the following for each of the required topics in its cyber security policy:

#### 1.1 Personnel & training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

### 1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN “split-tunneling” or “dual-homed” workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity’s Interactive Remote Access controls

### 1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

### 1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

### 1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

### 1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components

- Availability of system backups

### 1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

### 1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

### 1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

The Standard Drafting Team (SDT) has removed requirements relating to exceptions to a Responsible Entity's security policies since it is a general management issue that is not within the scope of a reliability requirement. The SDT considers it to be an internal policy requirement and not a reliability requirement. However, the SDT encourages Responsible Entities to continue this practice as a component of its cyber security policy.

In this and all subsequent required approvals in the NERC CIP Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

#### **Requirement R2:**

As with Requirement R1, the number of policies and their specific language would be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization or as components of specific programs. The cyber security policy must cover in sufficient detail the four topical areas required by CIP-003-5(X), Requirement R2. The Responsible Entity has flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R2. The intent of the requirement is to outline a set of basic protections that all low impact BES Cyber Systems should receive without requiring a significant administrative and compliance overhead. The SDT intends that demonstration of this requirement can be reasonably accomplished through providing evidence of related processes, procedures, or plans. While the audit staff may choose to review an example low impact BES Cyber System, the SDT believes strongly that the current method (as of this writing) of reviewing a statistical sample of systems

is not necessary. The SDT also notes that in topic 2.3, the SDT uses the term “electronic access control” in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing.

### **Requirement R3:**

The intent of CIP-003-5(X), Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that this CIP Senior Manager play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

### **Requirement R4:**

As indicated in the rationale for CIP-003-5(X), Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the Responsible Entity should have significant flexibility to adapt this requirement to their existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records provides a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up to date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

## **Rationale:**

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

### **Rationale for R1:**

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

Annual review and approval of the cyber security policy ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

### **Rationale for R2:**

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

The language in Requirement R2, Part 2.3 “. . . for external routable protocol connections and Dial-up Connectivity . . .” was included to acknowledge the support given in FERC Order 761, paragraph 87, for electronic security perimeter protections “of some form” to be applied to all BES Cyber Systems, regardless of impact. Part 2.3 uses the phrase “external routable protocol connections” instead of the defined term “External Routable Connectivity,” because the latter term has very specific connotations relating to Electronic Security Perimeters and high and medium impact BES Cyber Systems. Using the glossary term “External Routable Connectivity” in the context of Requirement R2 would not be appropriate because Requirement R2 is limited in scope to low impact BES Cyber Systems.

Review and approval of the cyber security policy at least every 15 calendar months ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

**Rationale for R3:**

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the *Glossary of Terms used in NERC Reliability Standards* so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has “the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards” which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the senior manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

**Rationale for R4:**

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

## Version History

| Version     | Date       | Action  | Change Tracking   |
|-------------|------------|---|---|
| 1           | 1/16/06    | R3.2 — Change “Control Center” to “control center.”   | 3/24/06   |
| 2           | 9/30/09    | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3           | 12/16/09   | Updated version number from -2 to -3 Approved by the NERC Board of Trustees.  |   |
| 3           | 3/31/10    | Approved by FERC.   |   |
| 4           | 1/24/11    | Approved by the NERC Board of Trustees.   | Update to conform to changes to CIP-002-4 (Project 2008-06)                               |
| 5           | 11/26/12   | Adopted by the NERC Board of Trustees.  | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |
| 5           | 11/22/13   | FERC Order issued approving CIP-003-5. (Order becomes effective 2/3/14.)  |   |
| <u>5(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial</u>             |

|  |  |  |                                  |
|--|--|--|----------------------------------|
|  |  |  | <u>Action Scheme<br/>and RAS</u> |
|--|--|--|----------------------------------|



## A. Introduction

1. **Title:** Cyber Security — Personnel & Training
2. **Number:** CIP-004-5.1(X)
3. **Purpose:** To minimize the risk against compromise that could lead to misoperation or instability in the BES from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES Cyber Systems.

### 4. Applicability:

**4.1. Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

#### 4.1.1. Balancing Authority

**4.1.2. Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

**4.1.2.1.** Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

**4.1.2.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.1.2.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.1.2.2.** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.1.2.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.1.2.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

#### 4.1.3. Generator Operator

#### 4.1.4. Generator Owner

#### 4.1.5. Interchange Coordinator or Interchange Authority

#### 4.1.6. Reliability Coordinator

**4.1.7. Transmission Operator**

**4.1.8. Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1. Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1.** Each UFLS or UVLS System that:

**4.2.1.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2.** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3. Exemptions:** The following are exempt from Standard CIP-004-5.1(X):

**4.2.3.1.** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5.** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-004-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-004-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-004-5.1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X) and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

**B. Requirements and Measures**

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-004-5.1(X) Table R1 – Security Awareness Program |  |   |   |
|--|--|---|---|
| Part   | Applicable Systems   | Requirements  | Measures  |
| 1.1  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity’s personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Systems. | <p>An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as:</p> <ul style="list-style-type: none"> <li>• direct communications (for example, e-mails, memos, computer-based training); or</li> <li>• indirect communications (for example, posters, intranet, or brochures); or</li> <li>• management support and reinforcement (for example, presentations or meetings).</li> </ul> |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program*. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- M2.** Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

| CIP-004-5.1(X) Table R2 – Cyber Security Training Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Training content on:</p> <ol style="list-style-type: none"> <li>2.1.1. Cyber security policies;</li> <li>2.1.2. Physical access controls;</li> <li>2.1.3. Electronic access controls;</li> <li>2.1.4. The visitor control program;</li> <li>2.1.5. Handling of BES Cyber System Information and its storage;</li> <li>2.1.6. Identification of a Cyber Security Incident and initial notifications in accordance with the entity’s incident response plan;</li> <li>2.1.7. Recovery plans for BES Cyber Systems;</li> <li>2.1.8. Response to Cyber Security Incidents; and</li> <li>2.1.9. Cyber security risks associated with a BES Cyber System’s electronic interconnectivity and interoperability with other Cyber Assets.</li> </ol> | <p>Examples of evidence may include, but are not limited to, training material such as power point presentations, instructor notes, student notes, handouts, or other training materials.</p> |



| CIP-004-5.1(X) Table R2 – Cyber Security Training Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Require completion of the training specified in Part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable Cyber Assets, except during CIP Exceptional Circumstances.</p> | <p>Examples of evidence may include, but are not limited to, training records and documentation of when CIP Exceptional Circumstances were invoked.</p> |
| 2.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Require completion of the training specified in Part 2.1 at least once every 15 calendar months.</p>   | <p>Examples of evidence may include, but are not limited to, dated individual training records.</p>   |

**R3.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented personnel risk assessment programs to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

**M3.** Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |                              |   |
|---|---|------------------------------|---|
| Part  | Applicable Systems  | Requirements                 | Measures  |
| 3.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | Process to confirm identity. | An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to confirm identity. |

| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 3.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Process to perform a seven year criminal history records check as part of each personnel risk assessment that includes:</p> <ol style="list-style-type: none"> <li>3.2.1. current residence, regardless of duration; and</li> <li>3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has resided for six consecutive months or more.</li> </ol> <p>If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.</p> | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to perform a seven year criminal history records check.</p> |

| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 3.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Criteria or process to evaluate criminal history records checks for authorizing access.</p>  | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to evaluate criminal history records checks.</p>   |
| 3.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Criteria or process for verifying that personnel risk assessments performed for contractors or service vendors are conducted according to Parts 3.1 through 3.3.</p> | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s criteria or process for verifying contractors or service vendors personnel risk assessments.</p> |

| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 3.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Process to ensure that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed according to Parts 3.1 to 3.4 within the last seven years.</p> | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process for ensuring that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed within the last seven years.</p> |

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access management programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M4.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

| CIP-004-5.1(X) Table R4 – Access Management Program |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 4.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances:</p> <ol style="list-style-type: none"> <li>4.1.1. Electronic access;</li> <li>4.1.2. Unescorted physical access into a Physical Security Perimeter; and</li> <li>4.1.3. Access to designated storage locations, whether physical or electronic, for BES Cyber System Information.</li> </ol> | <p>An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a Physical Security Perimeter, and access to designated storage locations, whether physical or electronic, for BES Cyber System Information.</p> |

| CIP-004-5.1(X) Table R4 – Access Management Program |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 4.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or</li> <li>• Dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).</li> </ul> |

| CIP-004-5.1(X) Table R4 – Access Management Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 4.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>For electronic access, verify at least once every 15 calendar months that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.</p> | <p>An example of evidence may include, but is not limited to, documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> <li>1. A dated listing of all accounts/account groups or roles within the system;</li> <li>2. A summary description of privileges associated with each group or role;</li> <li>3. Accounts assigned to the group or role; and</li> <li>4. Dated evidence showing verification of the privileges for the group are authorized and appropriate to the work function performed by people assigned to each account.</li> </ol> |



| CIP-004-5.1(X) Table R4 – Access Management Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 4.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Verify at least once every 15 calendar months that access to the designated storage locations for BES Cyber System Information, whether physical or electronic, are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.</p> | <p>An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> <li>1. A dated listing of authorizations for BES Cyber System information;</li> <li>2. Any privileges associated with the authorizations; and</li> <li>3. Dated evidence showing a verification of the authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.</li> </ol> |

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access revocation programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Planning].
- M5.** Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-004-5.1(X) Table R5 – Access Revocation |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 5.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>A process to initiate removal of an individual’s ability for unescorted physical access and Interactive Remote Access upon a termination action, and complete the removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).</p> | <p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated workflow or sign-off form verifying access removal associated with the termination action; and</li> <li>2. Logs or other demonstration showing such persons no longer have access.</li> </ol> |

| CIP-004-5.1(X) Table R5 – Access Revocation |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 5.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>For reassignments or transfers, revoke the individual’s authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next calendar day following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p> | <p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated workflow or sign-off form showing a review of logical and physical access; and</li> <li>2. Logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.</li> </ol> |

| CIP-004-5.1(X) Table R5 – Access Revocation |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 5.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>For termination actions, revoke the individual’s access to the designated storage locations for BES Cyber System Information, whether physical or electronic (unless already revoked according to Requirement R5.1), by the end of the next calendar day following the effective date of the termination action.</p> | <p>An example of evidence may include, but is not limited to, workflow or sign-off form verifying access removal to designated physical areas or cyber systems containing BES Cyber System Information associated with the terminations and dated within the next calendar day of the termination action.</p> |

| CIP-004-5.1(X) Table R5 – Access Revocation |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 5.4   | High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> <li>EACMS</li> </ul> | For termination actions, revoke the individual’s non-shared user accounts (unless already revoked according to Parts 5.1 or 5.3) within 30 calendar days of the effective date of the termination action. | An example of evidence may include, but is not limited to, workflow or sign-off form showing access removal for any individual BES Cyber Assets and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions. |

| CIP-004-5.1(X) Table R5 – Access Revocation |  |   |  |
|---|--|---|--|
| Part  | Applicable Systems   | Requirements  | Measures   |
| 5.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>EACMS</li> </ul> | <p>For termination actions, change passwords for shared account(s) known to the user within 30 calendar days of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 calendar days following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p> <p>If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 calendar days following the end of the operating circumstances.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>Workflow or sign-off form showing password reset within 30 calendar days of the termination;</li> <li>Workflow or sign-off form showing password reset within 30 calendar days of the reassignments or transfers; or</li> <li>Documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 calendar days following the end of the operating circumstance.</li> </ul> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels (CIP-004-5.1(X))  |  |  |   |
|-----|---------------------|-------|---|--|--|---|
|     |                     |       | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
| R1  | Operations Planning | Lower | The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so less than 10 calendar days after the start of a subsequent calendar quarter. (1.1) | The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so between 10 and 30 calendar days after the start of a subsequent calendar quarter. (1.1)       | The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so within the subsequent quarter but beyond 30 calendar days after the start of that calendar quarter. (1.1) | The Responsible Entity did not document or implement any security awareness process(es) to reinforce cyber security practices. (R1)<br><br>OR<br><br>The Responsible Entity did not reinforce cyber security practices and associated physical security practices for at least two consecutive calendar quarters. (1.1) |
| R2  | Operations Planning | Lower | The Responsible Entity implemented a cyber security training program but failed to include one of the training  | The Responsible Entity implemented a cyber security training program but failed to include two of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess | The Responsible Entity implemented a cyber security training program but failed to include three of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess           | The Responsible Entity did not implement a cyber security training program appropriate to individual roles, functions, or responsibilities. (R2)<br><br>OR  |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |  |   |
|-----|--------------|-----|---|---|--|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL  |
|     |              |     | <p>content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized</p> | <p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals with authorized</p> | <p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals with authorized electronic or authorized</p> | <p>The Responsible Entity implemented a cyber security training program but failed to include four or more of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |  |   |
|-----|--------------|-----|--|---|--|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL  |
|     |              |     | <p>unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion</p> | <p>electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p> | <p>unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p> | <p>identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p> |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-004-5.1(X))   |   |   |  |
|-----------|----------------------------|---------------|--|---|---|--|
|           |                            |               | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|           |                            |               | date, and did not identify, assess and correct the deficiencies. (2.3)   |   |   |  |
| <b>R3</b> | <b>Operations Planning</b> | <b>Medium</b> | <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access</p> | <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for two individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p> | <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for three individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p> | <p>The Responsible Entity did not have all of the required elements as described by 3.1 through 3.4 included within documented program(s) for implementing Personnel Risk Assessments (PRAs), for individuals, including contractors and service vendors, for obtaining and retaining authorized cyber or authorized unescorted physical access. (R3)</p> <p>OR</p> <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | for one individual, and did not identify, assess, and correct the deficiencies. (R3)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for one | contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for two individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)<br>OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for two individuals, and did not identify, assess, and | contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for three individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)<br>OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for three individuals, and did not identify, assess, and | for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for four or more individuals, and did not identify, assess, and correct the deficiencies. (R3)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |   |  |
|-----|--------------|-----|---|---|---|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | individual, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)<br>OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required | correct the deficiencies. (3.2 & 3.4)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for two individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4)<br>OR<br>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for two individuals with authorized electronic or authorized unescorted | correct the deficiencies. (3.2 & 3.4)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for three individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4)<br>OR<br>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for three individuals with authorized electronic or authorized unescorted | OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.2 & 3.4)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |   |   |
|-----|--------------|-----|--|---|---|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>checks described in 3.2.1 and 3.2.2 for one individual, and did not identify, assess, and correct the deficiencies. (3.2 &amp; 3.4)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access</p> | <p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p> | <p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p> | <p>authorized unescorted physical access but did not evaluate criminal history records check for access authorization for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.3 &amp; 3.4)</p> <p>OR</p> <p>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for four or more individuals with authorized electronic or authorized unescorted physical access within 7 calendar years of the previous PRA completion date and has identified deficiencies, and did not identify, assess, and correct the deficiencies. (3.5)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |              |          |            |
|-----|--------------|-----|---|--------------|----------|------------|
|     |              |     | Lower VSL   | Moderate VSL | High VSL | Severe VSL |
|     |              |     | <p>but did not evaluate criminal history records check for access authorization for one individual, and did not identify, assess, and correct the deficiencies. (3.3 &amp; 3.4)</p> <p>OR</p> <p>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for one individual with authorized electronic or authorized unescorted physical access within 7</p> |              |          |            |

| R #       | Time Horizon                                       | VRF           | Violation Severity Levels (CIP-004-5.1(X))  |  |  |  |
|-----------|--|---------------|---|--|--|--|
|           |  |               | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|           |  |               | calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)   |  |  |  |
| <b>R4</b> | <b>Operations Planning and Same Day Operations</b> | <b>Medium</b> | The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so less than 10 calendar days after the start | The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 10 and 20 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2)<br><br>OR | The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 20 and 30 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2)<br><br>OR | The Responsible Entity did not implement any documented program(s) for access management. (R4)<br><br>OR<br>The Responsible Entity has implemented one or more documented program(s) for access management that includes a process to authorize electronic access, unescorted physical access, or access to the designated storage locations where |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>of a subsequent calendar quarter, and did not identify, assess and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15</p> | <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for two BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p> | <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for three BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p> | <p>BES Cyber System Information is located, and did not identify, assess, and correct the deficiencies. (4.1)</p> <p>OR</p> <p>The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records for at least two consecutive calendar quarters, and did not identify, assess, and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |   |   |
|-----|--------------|-----|--|---|---|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>calendar months of the previous verification but for one BES Cyber System, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is</p> | <p>calendar months of the previous verification but for two BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)</p> | <p>calendar months of the previous verification but for three BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)</p> | <p>privileges are correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber System Information storage locations, privileges</p> |

| R # | Time Horizon                                | VRF    | Violation Severity Levels (CIP-004-5.1(X))   |  |  |   |
|-----|---|--------|--|--|--|---|
|     |   |        | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|     |   |        | correct and necessary within 15 calendar months of the previous verification but for one BES Cyber System Information storage location, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.4) |  |  | were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)  |
| R5  | Same Day Operations and Operations Planning | Medium | The Responsible Entity has implemented one or more process(es) to revoke the individual's  | The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or | The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or | The Responsible Entity has not implemented any documented program(s) for access revocation for electronic access, unescorted physical access, or BES Cyber System |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |   |  |
|-----|--------------|-----|--|---|---|--|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | <p>access to the designated storage locations for BES Cyber System Information but, for one individual, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> <p>OR</p> <p>The Responsible Entity has implemented</p> | <p>complete the removal within 24 hours of the termination action but did not initiate those removals for one individual, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for one individual, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p> | <p>complete the removal within 24 hours of the termination action but did not initiate those removals for two individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for two individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p> | <p>Information storage locations. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or complete the removal within 24 hours of the termination action but did not initiate those removals for three or more individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |  |  |   |
|-----|--------------|-----|---|--|--|---|
|     |              |     | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|     |              |     | <p>one or more process(es) to revoke the individual’s user accounts upon termination action but did not do so for within 30 calendar days of the date of termination action for one or more individuals, and did not identify, assess, and correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to</p> | <p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for two individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> | <p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for three or more individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> | <p>requires retention of access following reassignments or transfers but, for three or more individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |              |          |            |
|-----|--------------|-----|--|--------------|----------|------------|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL |
|     |              |     | change passwords for shared accounts known to the user upon termination action, reassignment, or transfer, but did not do so for within 30 calendar days of the date of termination action, reassignment, or transfer for one or more individuals, and did not identify, assess, and correct the deficiencies.<br>(5.5)<br><br>OR<br><br>The Responsible |              |          |            |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |              |          |            |
|-----|--------------|-----|--|--------------|----------|------------|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL |
|     |              |     | Entity has implemented one or more process(es) to determine and document extenuating operating circumstances following a termination action, reassignment, or transfer, but did not change one or more passwords for shared accounts known to the user within 10 calendar days following the end of the extenuating operating circumstances, and did not |              |          |            |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))               |              |          |            |
|-----|--------------|-----|--|--------------|----------|------------|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL |
|     |              |     | identify, assess, and correct the deficiencies.<br>(5.5) |              |          |            |



**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Guidelines and Technical Basis**

**Section 4 – Scope of Applicability of the CIP Cyber Security Standards**

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)'s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

**Requirement R1:**

The security awareness program is intended to be an informational program, not a formal training program. It should reinforce security practices to ensure that personnel maintain awareness of best practices for both physical and electronic security to protect its BES Cyber Systems. The Responsible Entity is not required to provide records that show that each individual received or understood the information, but they must maintain documentation of the program materials utilized in the form of posters, memos, and/or presentations.

Examples of possible mechanisms and evidence, when dated, which can be used are:

- Direct communications (e.g., emails, memos, computer based training, etc.);
- Indirect communications (e.g., posters, intranet, brochures, etc.);
- Management support and reinforcement (e.g., presentations, meetings, etc.).

### **Requirement R2:**

Training shall cover the policies, access controls, and procedures as developed for the BES Cyber Systems and include, at a minimum, the required items appropriate to personnel roles and responsibilities from Table R2. The Responsible Entity has the flexibility to define the training program and it may consist of multiple modules and multiple delivery mechanisms, but a single training program for all individuals needing to be trained is acceptable. The training can focus on functions, roles or responsibilities at the discretion of the Responsible Entity.

One new element in the training content is intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems as per FERC Order No. 706, Paragraph 434. This is not intended to provide technical training to individuals supporting networking hardware and software, but educating system users of the cyber security risks associated with the interconnectedness of these systems. The users, based on their function, role or responsibility, should have a basic understanding of which systems can be accessed from other systems and how the actions they take can affect cyber security.

Each Responsible Entity shall ensure all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, complete cyber security training prior to their being granted authorized access, except for CIP Exceptional Circumstances. To retain the authorized accesses, individuals must complete the training at least one every 15 months.

### **Requirement R3:**

Each Responsible Entity shall ensure a personnel risk assessment is performed for all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, prior to their being granted authorized access, except for program specified exceptional circumstances that are approved by the single senior management official or their delegate and impact the reliability of the BES or emergency response. Identity should be confirmed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. Identity only needs to be confirmed prior to initially granting access and only requires periodic confirmation according to the entity's process during the tenure of employment, which may or may not be the same as the initial verification action.

A seven year criminal history check should be performed for those locations where the individual has resided for at least six consecutive months. This check should also be performed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. When it is not possible to perform a full seven year criminal history check, documentation must be made of what criminal history check was performed, and the reasons a full seven-year check could not be performed. Examples of this could include

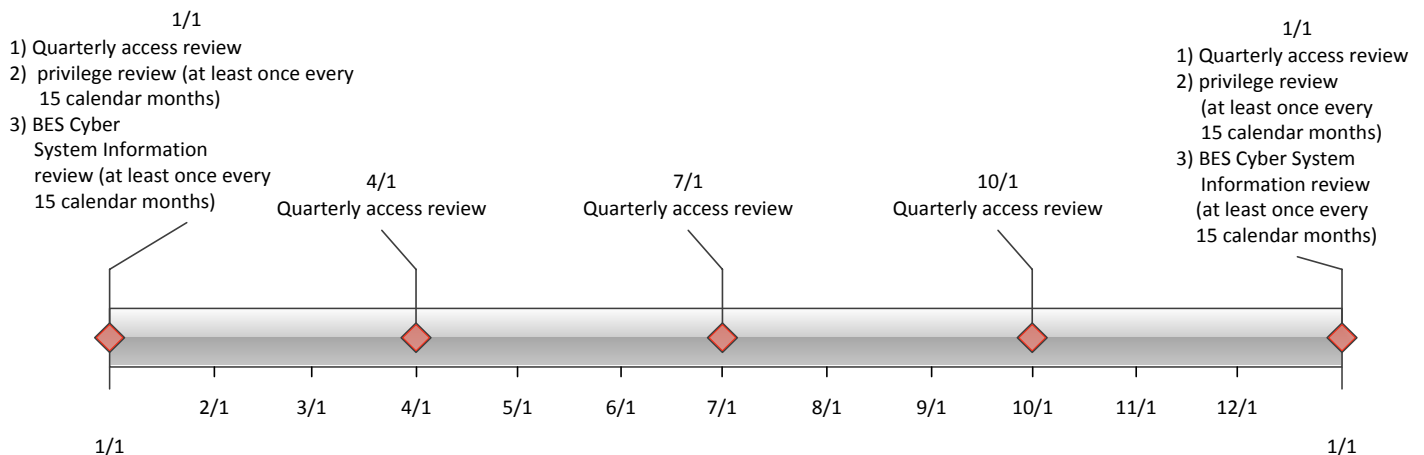
individuals under the age of 25 where a juvenile criminal history may be protected by law, individuals who may have resided in locations from where it is not possible to obtain a criminal history records check, violates the law or is not allowed under the existing collective bargaining agreement. The Responsible Entity should consider the absence of information for the full seven years when assessing the risk of granting access during the process to evaluate the criminal history check. There needs to be a personnel risk assessment that has been completed within the last seven years for each individual with access. A new criminal history records check must be performed as part of the new PRA. Individuals who have been granted access under a previous version of these standards need a new PRA within seven years of the date of their last PRA. The clarifications around the seven year criminal history check in this version do not require a new PRA be performed by the implementation date.

**Requirement R4:**

Authorization for electronic and unescorted physical access and access to BES Cyber System Information must be on the basis of necessity in the individual performing a work function. Documentation showing the authorization should have some justification of the business need included. To ensure proper segregation of duties, access authorization and provisioning should not be performed by the same person where possible.

This requirement specifies both quarterly reviews and reviews at least once every 15 calendar months. Quarterly reviews are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

The privilege review at least once every 15 calendar months is more detailed to ensure an individual’s associated privileges are the minimum necessary to perform their work function



(i.e., least privilege). Entities can more efficiently perform this review by implementing role-based access. This involves determining the specific roles on the system (e.g., system operator, technician, report viewer, administrator, etc.) then grouping access privileges to the role and assigning users to the role. Role-based access does not assume any specific software and can be implemented by defining specific provisioning processes for each role where access group assignments cannot be performed. Role-based access permissions eliminate the need to perform the privilege review on individual accounts. An example timeline of all the reviews in Requirement R4 is included below.

Separation of duties should be considered when performing the reviews in Requirement R4. The person reviewing should be different than the person provisioning access.

If the results of quarterly or at least once every 15 calendar months account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that this error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

**Requirement R5:**

The requirement to revoke access at the time of the termination action includes procedures showing revocation of access concurrent with the termination action. This requirement recognizes that the timing of the termination action may vary depending on the circumstance. Some common scenarios and possible processes on when the termination action occurs are provided in the following table. These scenarios are not an exhaustive list of all scenarios, but are representative of several routine business practices.

| Scenario   | Possible Process  |
|--|---|
| Immediate involuntary termination  | Human resources or corporate security escorts the individual off site and the supervisor or human resources personnel notify the appropriate personnel to begin the revocation process. |
| Scheduled involuntary termination  | Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.                          |
| Voluntary termination  | Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.                          |
| Retirement where the last working day is several weeks prior to the termination date | Human resources personnel coordinate with manager to determine the final date access is no longer needed and schedule the revocation of access on the determined day.                   |

|       |  |
|-------|--|
| Death | Human resources personnel are notified of the death and work with appropriate personnel to begin the revocation process. |
|-------|--|

Revocation of electronic access should be understood to mean a process with the end result that electronic access to BES Cyber Systems is no longer possible using credentials assigned to or known by the individual(s) whose access privileges are being revoked. Steps taken to accomplish this outcome may include deletion or deactivation of accounts used by the individual(s), but no specific actions are prescribed. Entities should consider the ramifications of deleting an account may include incomplete event log entries due to an unrecognized account or system services using the account to log on.

The initial revocation required in Requirement R5.1 includes unescorted physical access and Interactive Remote Access. These two actions should prevent any further access by the individual after termination. If an individual still has local access accounts (i.e., accounts on the Cyber Asset itself) on BES Cyber Assets, then the Responsible Entity has 30 days to complete the revocation process for those accounts. However, nothing prevents a Responsible Entity from performing all of the access revocation at the time of termination.

For transferred or reassigned individuals, a review of access privileges should be performed. This review could entail a simple listing of all authorizations for an individual and working with the respective managers to determine which access will still be needed in the new position. For instances in which the individual still needs to retain access as part of a transitory period, the entity should schedule a time to review these access privileges or include the privileges in the quarterly account review or annual privilege review.

Revocation of access to shared accounts is called out separately to prevent the situation where passwords on substation and generation devices are constantly changed due to staff turnover.

Requirement 5.5 specified that passwords for shared account are to be changed within 30 calendar days of the termination action or when the Responsible Entity determines an individual no longer requires access to the account as a result of a reassignment or transfer. The 30 days applies under normal operating conditions. However, circumstances may occur where this is not possible. Some systems may require an outage or reboot of the system in order to complete the password change. In periods of extreme heat or cold, many Responsible Entities may prohibit system outages and reboots in order to maintain reliability of the BES. When these circumstances occur, the Responsible Entity must document these circumstances and prepare to change the password within 10 calendar days following the end of the operating circumstances. Records of activities must be retained to show that the Responsible Entity followed the plan they created.



## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

Ensures that Responsible Entities with personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Assets take action so that those personnel with such authorized electronic or authorized unescorted physical access maintain awareness of the Responsible Entity's security practices.

**Summary of Changes:** Reformatted into table structure.

**Reference to prior version:** (Part 1.1) CIP-004-4, R1

**Change Rationale:** (Part 1.1)

*Changed to remove the need to ensure or prove everyone with authorized electronic or authorized unescorted physical access "received" ongoing reinforcement – to state that security awareness has been reinforced.*

*Moved example mechanisms to guidance.*

### **Rationale for R2:**

To ensure that the Responsible Entity's training program for personnel who need authorized electronic access and/or authorized unescorted physical access to BES Cyber Systems covers the proper policies, access controls, and procedures to protect BES Cyber Systems and are trained before access is authorized.

Based on their role, some personnel may not require training on all topics.

### **Summary of Changes:**

1. Addition of specific role training for:

- The visitor control program
- Electronic interconnectivity supporting the operation and control of BES Cyber Systems
- Storage media as part of the handling of BES Cyber Systems information

2. Change references from Critical Cyber Assets to BES Cyber Systems.

**Reference to prior version:** (Part 2.1) CIP004-4, R2.2.1

**Change Rationale:** (Part 2.1)

*Removed "proper use of Critical Cyber Assets" concept from previous versions to focus the requirement on cyber security issues, not the business function. The previous version was*

*focused more on the business or functional use of the BES Cyber System and is outside the scope of cyber security. Personnel who will administer the visitor control process or serve as escorts for visitors need training on the program. Core training on the handling of BES Cyber System (not Critical Cyber Assets) Information, with the addition of storage; FERC Order No. 706, paragraph 413 and paragraphs 632-634, 688, 732-734; DHS 2.4.16. Core training on the identification and reporting of a Cyber Security Incident; FERC Order No. 706, Paragraph 413; Related to CIP-008-5(X) & DHS Incident Reporting requirements for those with roles in incident reporting. Core training on the action plans and procedures to recover or re-establish BES Cyber Systems for personnel having a role in the recovery; FERC Order No. 706, Paragraph 413. Core training programs are intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems; FERC Order No. 706, Paragraph 434.*

**Reference to prior version:** (Part 2.2) CIP004-4, R2.1

**Change Rationale:** (Part 2.2)

*Addition of exceptional circumstances parameters as directed in FERC Order No. 706, Paragraph 431 is detailed in CIP-003-5(X).*

**Reference to prior version:** (Part 2.3) CIP004-4, R2.3

**Change Rationale:** (Part 2.3)

*Updated to replace “annually” with “once every 15 calendar months.”*

### **Rationale for R3:**

To ensure that individuals who need authorized electronic or authorized unescorted physical access to BES Cyber Systems have been assessed for risk. Whether initial access or maintaining access, those with access must have had a personnel risk assessment completed within the last 7 years.

**Summary of Changes:** Specify that the seven year criminal history check covers all locations where the individual has resided for six consecutive months or more, including current residence regardless of duration.

**Reference to prior version:** (Part 3.1) CIP004-4, R3.1

**Change Rationale:** (Part 3.1)

*Addressed interpretation request in guidance. Specified that process for identity confirmation is required. The implementation plan clarifies that a documented identity verification conducted under an earlier version of the CIP standards is sufficient.*

**Reference to prior version:** (Part 3.2) CIP004-4, R3.1

**Change Rationale:** (Part 3.2)

*Specify that the seven year criminal history check covers all locations where the individual has resided for six months or more, including current residence regardless of duration. Added*



*additional wording based on interpretation request. Provision is made for when a full seven-year check cannot be performed.*

**Reference to prior version:** (Part 3.3) New

**Change Rationale:** (Part 3.3)

*There should be documented criteria or a process used to evaluate criminal history records checks for authorizing access.*

**Reference to prior version:** (Part 3.4) CIP-004-4, R3.3

**Change Rationale:** (Part 3.4)

*Separated into its own table item.*

**Reference to prior version:** (Part 3.5) CIP-004-3, R3, R3.3

**Change Rationale:** (Part 3.5)

*Whether for initial access or maintaining access, establishes that those with access must have had PRA completed within 7 years. This covers both initial and renewal. The implementation plan specifies that initial performance of this requirement is 7 years after the last personnel risk assessment that was performed pursuant to a previous version of the CIP Cyber Security Standards for a personnel risk assessment. CIP-004-3, R3, R3.3*

#### **Rationale for R4:**

To ensure that individuals with access to BES Cyber Systems and the physical and electronic locations where BES Cyber System Information is stored by the Responsible Entity have been properly authorized for such access. "Authorization" should be considered to be a grant of permission by a person or persons empowered by the Responsible Entity to perform such grants and included in the delegations referenced in CIP-003-5(X). "Provisioning" should be considered the actions to provide access to an individual.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (i.e., physical access control system, remote access system, directory services).

CIP Exceptional Circumstances are defined in a Responsible Entity's policy from CIP-003-5(X) and allow an exception to the requirement for authorization to BES Cyber Systems and BES Cyber System Information.

Quarterly reviews in Part 4.5 are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to access the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account

databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

If the results of quarterly or annual account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that the error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

**Summary of Changes:** The primary change was in pulling the access management requirements from CIP-003-4, CIP-004-4, and CIP-007-4 into a single requirement. The requirements from Version 4 remain largely unchanged except to clarify some terminology. The purpose for combining these requirements is to remove the perceived redundancy in authorization and review. The requirement in CIP-004-4 R4 to maintain a list of authorized personnel has been removed because the list represents only one form of evidence to demonstrate compliance that only authorized persons have access.

**Reference to prior version:** (Part 4.1) CIP 003-4, R5.1 and R5.2; CIP-006-4, R1.5 and R4; CIP-007-4, R5.1 and R5.1.1

**Change Rationale:** (Part 4.1)

Combined requirements from CIP-003-4, CIP-007-4, and CIP-006-4 to make the authorization process clear and consistent. *CIP-003-4, CIP-004-4, CIP-006-4, and CIP-007-4 all reference authorization of access in some form, and CIP-003-4 and CIP-007-4 require authorization on a “need to know” basis or with respect to work functions performed. These were consolidated to ensure consistency in the requirement language.*

**Reference to prior version:** (Part 4.2) CIP 004-4, R4.1

**Change Rationale:** (Part 4.2)

*Feedback among team members, observers, and regional CIP auditors indicates there has been confusion in implementation around what the term “review” entailed in CIP-004-4, Requirement R4.1. This requirement clarifies the review should occur between the provisioned access and authorized access.*

**Reference to prior version:** (Part 4.3) CIP 007-4, R5.1.3

**Change Rationale:** (Part 4.3)

*Moved requirements to ensure consistency and eliminate the cross-referencing of requirements. Clarified what was necessary in performing verification by stating the objective was to confirm that access privileges are correct and the minimum necessary.*

**Reference to prior version:** (Part 4.4) CIP-003-4, R5.1.2

**Change Rationale:** (Part 4.4)

*Moved requirement to ensure consistency among access reviews. Clarified precise meaning of annual. Clarified what was necessary in performing a verification by stating the objective was to*

*confirm access privileges are correct and the minimum necessary for performing assigned work functions.*

**Rationale for R5:**

The timely revocation of electronic access to BES Cyber Systems is an essential element of an access management regime. When an individual no longer requires access to a BES Cyber System to perform his or her assigned functions, that access should be revoked. This is of particular importance in situations where a change of assignment or employment is involuntary, as there is a risk the individual(s) involved will react in a hostile or destructive manner.

In considering how to address directives in FERC Order No. 706 directing “immediate” revocation of access for involuntary separation, the SDT chose not to specify hourly time parameters in the requirement (e.g., revoking access within 1 hour). The point in time at which an organization terminates a person cannot generally be determined down to the hour. However, most organizations have formal termination processes, and the timeliest revocation of access occurs in concurrence with the initial processes of termination.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (e.g., physical access control system, remote access system, directory services).

**Summary of Changes:** FERC Order No. 706, Paragraphs 460 and 461, state the following: “The Commission adopts the CIP NOPR proposal to direct the ERO to develop modifications to CIP-004-1 to require immediate revocation of access privileges when an employee, contractor or vendor no longer performs a function that requires physical or electronic access to a Critical Cyber Asset for any reason (including disciplinary action, transfer, retirement, or termination).

As a general matter, the Commission believes that revoking access when an employee no longer needs it, either because of a change in job or the end of employment, must be immediate.”

**Reference to prior version:** (Part 5.1) CIP 004-4, R4.2

**Change Rationale:** (Part 5.1)

*The FERC Order No. 706, Paragraphs 460 and 461, directs modifications to the Standards to **require immediate revocation** for any person no longer needing access. To address this directive, this requirement specifies revocation concurrent with the termination instead of within 24 hours.*

**Reference to prior version:** (Part 5.2) CIP-004-4, R4.2

**Change Rationale:** (Part 5.2)

*FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access, including transferred employees. In reviewing how to modify this requirement, the SDT determined the date a person no longer needs access after a transfer was problematic because the need may change over time. As a result, the SDT adapted this requirement from NIST 800-53 Version 3 to review access authorizations on the date of the transfer. The SDT felt this was a more effective control in accomplishing the objective to prevent a person from accumulating unnecessary authorizations through transfers.*

**Reference to prior version:** (Part 5.3) New

**Change Rationale:** (Part 5.3)

*FERC Order No. 706, Paragraph 386, directs modifications to the standards to require prompt revocation of access to protected information. To address this directive, Responsible Entities are required to revoke access to areas designated for BES Cyber System Information. This could include records closets, substation control houses, records management systems, file shares or other physical and logical areas under the Responsible Entity's control.*

**Reference to prior version:** (Part 5.4) New

**Change Rationale:** (Part 5.4)

*FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access. In order to meet the immediate timeframe, Responsible Entities will likely have initial revocation procedures to prevent remote and physical access to the BES Cyber System. Some cases may take more time to coordinate access revocation on individual Cyber Assets and applications without affecting reliability. This requirement provides the additional time to review and complete the revocation process. Although the initial actions already prevent further access, this step provides additional assurance in the access revocation process.*

**Reference to prior version:** (Part 5.5) CIP-007-4, R5.2.3

**Change Rationale:** (Part 5.5)

*To provide clarification of expected actions in managing the passwords.*

## Version History

| Version | Date     | Action   | Change Tracking   |
|---------|----------|--|---|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”  | 3/24/06   |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3       | 12/16/09 | Updated version number from -2 to -3<br>Approved by the NERC Board of Trustees.  |   |
| 3       | 3/31/10  | Approved by FERC.  |   |
| 4       | 12/30/10 | Modified to add specific criteria for Critical Asset identification.   | Update  |
| 4       | 1/24/11  | Approved by the NERC Board of Trustees.  | Update  |
| 5       | 11/26/12 | Adopted by the NERC Board of Trustees.   | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |
| 5.1     | 9/30/13  | Modified two VSLs in R4.   | Errata  |
| 5.1     | 11/22/13 | FERC Order issued approving CIP-004-5.1. (Order becomes effective on 2/3/14.)  |   |
| 5.1     | 4/2/14   | Address FERC Order 791 directive to modify Requirement R4 VRF and VSLs   | R4-VRF and VSLs   |

## Guidelines and Technical Basis

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|        |        |  |  |
|--------|--------|--|--|
| 5.1    | 5/6/14 | The NERC Board of Trustees adopted a revision to the VRF of Requirement 4 from Lower to Medium in CIP-004-5.1. |  |
| 5.1(X) | TBD    | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Cyber Security — Personnel & Training

2. **Number:** CIP-004-5.1(X)

3. **Purpose:** To minimize the risk against compromise that could lead to misoperation or instability in the BES from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES Cyber Systems.

### 4. Applicability:

**4.1. Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

#### 4.1.1. Balancing Authority

**4.1.2. Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

**4.1.2.1.** Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

**4.1.2.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.1.2.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.1.2.2.** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.1.2.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.1.2.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

#### 4.1.3. Generator Operator

#### 4.1.4. Generator Owner

#### 4.1.5. Interchange Coordinator or Interchange Authority

**4.1.6. Reliability Coordinator**

**4.1.7. Transmission Operator**

**4.1.8. Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1. Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1.** Each UFLS or UVLS System that:

**4.2.1.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2.** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3. Exemptions:** The following are exempt from Standard CIP-004-5.1(X):

**4.2.3.1.** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.



**4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5.** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

## 5. Effective Dates:

1. **24 Months Minimum** – CIP-004-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-004-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

## 6. Background:

Standard CIP-004-5.1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X) and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of

implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.

- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

**B. Requirements and Measures**

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-004-5.1(X) Table R1 – Security Awareness Program |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 1.1  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity’s personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Systems. | An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as: <ul style="list-style-type: none"> <li>• direct communications (for example, e-mails, memos, computer-based training); or</li> <li>• indirect communications (for example, posters, intranet, or brochures); or</li> <li>• management support and reinforcement (for example, presentations or meetings).</li> </ul> |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program*. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- M2.** Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

| CIP-004-5.1(X) Table R2 – Cyber Security Training Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Training content on:</p> <ol style="list-style-type: none"> <li>2.1.1. Cyber security policies;</li> <li>2.1.2. Physical access controls;</li> <li>2.1.3. Electronic access controls;</li> <li>2.1.4. The visitor control program;</li> <li>2.1.5. Handling of BES Cyber System Information and its storage;</li> <li>2.1.6. Identification of a Cyber Security Incident and initial notifications in accordance with the entity’s incident response plan;</li> <li>2.1.7. Recovery plans for BES Cyber Systems;</li> <li>2.1.8. Response to Cyber Security Incidents; and</li> <li>2.1.9. Cyber security risks associated with a BES Cyber System’s electronic interconnectivity and interoperability with other Cyber Assets.</li> </ol> | <p>Examples of evidence may include, but are not limited to, training material such as power point presentations, instructor notes, student notes, handouts, or other training materials.</p> |

| CIP-004-5.1(X) Table R2 – Cyber Security Training Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Require completion of the training specified in Part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable Cyber Assets, except during CIP Exceptional Circumstances.</p> | <p>Examples of evidence may include, but are not limited to, training records and documentation of when CIP Exceptional Circumstances were invoked.</p> |
| 2.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Require completion of the training specified in Part 2.1 at least once every 15 calendar months.</p>   | <p>Examples of evidence may include, but are not limited to, dated individual training records.</p>   |

**R3.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented personnel risk assessment programs to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

**M3.** Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |                              |   |
|---|---|------------------------------|---|
| Part  | Applicable Systems  | Requirements                 | Measures  |
| 3.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | Process to confirm identity. | An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to confirm identity. |



| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 3.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Process to perform a seven year criminal history records check as part of each personnel risk assessment that includes:</p> <ol style="list-style-type: none"> <li>3.2.1. current residence, regardless of duration; and</li> <li>3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has resided for six consecutive months or more.</li> </ol> <p>If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.</p> | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to perform a seven year criminal history records check.</p> |

| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 3.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Criteria or process to evaluate criminal history records checks for authorizing access.</p>  | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to evaluate criminal history records checks.</p>   |
| 3.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Criteria or process for verifying that personnel risk assessments performed for contractors or service vendors are conducted according to Parts 3.1 through 3.3.</p> | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s criteria or process for verifying contractors or service vendors personnel risk assessments.</p> |

| CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 3.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Process to ensure that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed according to Parts 3.1 to 3.4 within the last seven years.</p> | <p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process for ensuring that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed within the last seven years.</p> |

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access management programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M4.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

| CIP-004-5.1(X) Table R4 – Access Management Program |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 4.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances:</p> <ol style="list-style-type: none"> <li>4.1.1. Electronic access;</li> <li>4.1.2. Unescorted physical access into a Physical Security Perimeter; and</li> <li>4.1.3. Access to designated storage locations, whether physical or electronic, for BES Cyber System Information.</li> </ol> | <p>An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a Physical Security Perimeter, and access to designated storage locations, whether physical or electronic, for BES Cyber System Information.</p> |

CIP-004-5.1(X) Table R4 – Access Management Program

| Part | Applicable Systems  | Requirements   | Measures  |
|------|---|--|---|
| 4.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or</li> <li>• Dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).</li> </ul> |

CIP-004-5.1(X) Table R4 – Access Management Program

| Part | Applicable Systems  | Requirements  | Measures  |
|------|---|---|---|
| 4.3  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>For electronic access, verify at least once every 15 calendar months that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.</p> | <p>An example of evidence may include, but is not limited to, documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> <li>1. A dated listing of all accounts/account groups or roles within the system;</li> <li>2. A summary description of privileges associated with each group or role;</li> <li>3. Accounts assigned to the group or role; and</li> <li>4. Dated evidence showing verification of the privileges for the group are authorized and appropriate to the work function performed by people assigned to each account.</li> </ol> |

**CIP-004-5.1(X) Table R4 – Access Management Program**

| Part | Applicable Systems  | Requirements  | Measures  |
|------|---|---|---|
| 4.4  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Verify at least once every 15 calendar months that access to the designated storage locations for BES Cyber System Information, whether physical or electronic, are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.</p> | <p>An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> <li>1. A dated listing of authorizations for BES Cyber System information;</li> <li>2. Any privileges associated with the authorizations; and</li> <li>3. Dated evidence showing a verification of the authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.</li> </ol> |

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access revocation programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Planning].
- M5.** Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-004-5.1(X) Table R5 – Access Revocation |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 5.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>A process to initiate removal of an individual’s ability for unescorted physical access and Interactive Remote Access upon a termination action, and complete the removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).</p> | <p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated workflow or sign-off form verifying access removal associated with the termination action; and</li> <li>2. Logs or other demonstration showing such persons no longer have access.</li> </ol> |



| CIP-004-5.1(X) Table R5 – Access Revocation |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 5.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>For reassignments or transfers, revoke the individual’s authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next calendar day following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p> | <p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated workflow or sign-off form showing a review of logical and physical access; and</li> <li>2. Logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.</li> </ol> |

| CIP-004-5.1(X) Table R5 – Access Revocation |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 5.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>For termination actions, revoke the individual’s access to the designated storage locations for BES Cyber System Information, whether physical or electronic (unless already revoked according to Requirement R5.1), by the end of the next calendar day following the effective date of the termination action.</p> | <p>An example of evidence may include, but is not limited to, workflow or sign-off form verifying access removal to designated physical areas or cyber systems containing BES Cyber System Information associated with the terminations and dated within the next calendar day of the termination action.</p> |

| CIP-004-5.1(X) Table R5 – Access Revocation |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 5.4   | High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> <li>EACMS</li> </ul> | For termination actions, revoke the individual’s non-shared user accounts (unless already revoked according to Parts 5.1 or 5.3) within 30 calendar days of the effective date of the termination action. | An example of evidence may include, but is not limited to, workflow or sign-off form showing access removal for any individual BES Cyber Assets and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions. |

| CIP-004-5.1(X) Table R5 – Access Revocation |  |   |  |
|---|--|---|--|
| Part  | Applicable Systems   | Requirements  | Measures   |
| 5.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>EACMS</li> </ul> | <p>For termination actions, change passwords for shared account(s) known to the user within 30 calendar days of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 calendar days following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p> <p>If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 calendar days following the end of the operating circumstances.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>Workflow or sign-off form showing password reset within 30 calendar days of the termination;</li> <li>Workflow or sign-off form showing password reset within 30 calendar days of the reassignments or transfers; or</li> <li>Documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 calendar days following the end of the operating circumstance.</li> </ul> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels (CIP-004-5.1(X))  |  |  |   |
|-----|---------------------|-------|---|--|--|---|
|     |                     |       | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
| R1  | Operations Planning | Lower | The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so less than 10 calendar days after the start of a subsequent calendar quarter. (1.1) | The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so between 10 and 30 calendar days after the start of a subsequent calendar quarter. (1.1)       | The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so within the subsequent quarter but beyond 30 calendar days after the start of that calendar quarter. (1.1) | The Responsible Entity did not document or implement any security awareness process(es) to reinforce cyber security practices. (R1)<br><br>OR<br><br>The Responsible Entity did not reinforce cyber security practices and associated physical security practices for at least two consecutive calendar quarters. (1.1) |
| R2  | Operations Planning | Lower | The Responsible Entity implemented a cyber security training program but failed to include one of the training  | The Responsible Entity implemented a cyber security training program but failed to include two of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess | The Responsible Entity implemented a cyber security training program but failed to include three of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess           | The Responsible Entity did not implement a cyber security training program appropriate to individual roles, functions, or responsibilities. (R2)<br><br>OR  |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |  |   |
|-----|--------------|-----|---|---|--|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL  |
|     |              |     | <p>content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized</p> | <p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals with authorized</p> | <p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals with authorized electronic or authorized</p> | <p>The Responsible Entity implemented a cyber security training program but failed to include four or more of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |  |   |
|-----|--------------|-----|--|---|--|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL  |
|     |              |     | <p>unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion</p> | <p>electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p> | <p>unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p> | <p>identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p> |



| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-004-5.1(X))   |   |   |  |
|-----------|----------------------------|---------------|--|---|---|--|
|           |                            |               | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|           |                            |               | date, and did not identify, assess and correct the deficiencies. (2.3)   |   |   |  |
| <b>R3</b> | <b>Operations Planning</b> | <b>Medium</b> | <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access</p> | <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for two individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p> | <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for three individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p> | <p>The Responsible Entity did not have all of the required elements as described by 3.1 through 3.4 included within documented program(s) for implementing Personnel Risk Assessments (PRAs), for individuals, including contractors and service vendors, for obtaining and retaining authorized cyber or authorized unescorted physical access. (R3)</p> <p>OR</p> <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | for one individual, and did not identify, assess, and correct the deficiencies. (R3)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for one | contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for two individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)<br>OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for two individuals, and did not identify, assess, and | contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for three individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)<br>OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for three individuals, and did not identify, assess, and | for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for four or more individuals, and did not identify, assess, and correct the deficiencies. (R3)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |   |  |
|-----|--------------|-----|---|---|---|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | individual, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)<br>OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required | correct the deficiencies. (3.2 & 3.4)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for two individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4)<br>OR<br>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for two individuals with authorized electronic or authorized unescorted | correct the deficiencies. (3.2 & 3.4)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for three individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4)<br>OR<br>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for three individuals with authorized electronic or authorized unescorted | OR<br>The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.2 & 3.4)<br>OR<br>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |   |   |
|-----|--------------|-----|--|---|---|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>checks described in 3.2.1 and 3.2.2 for one individual, and did not identify, assess, and correct the deficiencies. (3.2 &amp; 3.4)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access</p> | <p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p> | <p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p> | <p>authorized unescorted physical access but did not evaluate criminal history records check for access authorization for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.3 &amp; 3.4)</p> <p>OR</p> <p>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for four or more individuals with authorized electronic or authorized unescorted physical access within 7 calendar years of the previous PRA completion date and has identified deficiencies, and did not identify, assess, and correct the deficiencies. (3.5)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |              |          |            |
|-----|--------------|-----|---|--------------|----------|------------|
|     |              |     | Lower VSL   | Moderate VSL | High VSL | Severe VSL |
|     |              |     | but did not evaluate criminal history records check for access authorization for one individual, and did not identify, assess, and correct the deficiencies.<br>(3.3 & 3.4)<br><br>OR<br><br>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for one individual with authorized electronic or authorized unescorted physical access within 7 |              |          |            |

| R #       | Time Horizon                                       | VRF           | Violation Severity Levels (CIP-004-5.1(X))  |  |  |  |
|-----------|--|---------------|---|--|--|--|
|           |  |               | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|           |  |               | calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)   |  |  |  |
| <b>R4</b> | <b>Operations Planning and Same Day Operations</b> | <b>Medium</b> | The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so less than 10 calendar days after the start | The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 10 and 20 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2)<br><br>OR | The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 20 and 30 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2)<br><br>OR | The Responsible Entity did not implement any documented program(s) for access management. (R4)<br><br>OR<br>The Responsible Entity has implemented one or more documented program(s) for access management that includes a process to authorize electronic access, unescorted physical access, or access to the designated storage locations where |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>of a subsequent calendar quarter, and did not identify, assess and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15</p> | <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for two BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p> | <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for three BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p> | <p>BES Cyber System Information is located, and did not identify, assess, and correct the deficiencies. (4.1)</p> <p>OR</p> <p>The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records for at least two consecutive calendar quarters, and did not identify, assess, and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |   |   |
|-----|--------------|-----|--|---|---|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>calendar months of the previous verification but for one BES Cyber System, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is</p> | <p>calendar months of the previous verification but for two BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)</p> | <p>calendar months of the previous verification but for three BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)</p> | <p>privileges are correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber System Information storage locations, privileges</p> |



| R # | Time Horizon                                | VRF    | Violation Severity Levels (CIP-004-5.1(X))   |  |  |   |
|-----|---|--------|--|--|--|---|
|     |   |        | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|     |   |        | correct and necessary within 15 calendar months of the previous verification but for one BES Cyber System Information storage location, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.4) |  |  | were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)  |
| R5  | Same Day Operations and Operations Planning | Medium | The Responsible Entity has implemented one or more process(es) to revoke the individual's  | The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or | The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or | The Responsible Entity has not implemented any documented program(s) for access revocation for electronic access, unescorted physical access, or BES Cyber System |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |   |   |  |
|-----|--------------|-----|--|---|---|--|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | <p>access to the designated storage locations for BES Cyber System Information but, for one individual, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> <p>OR</p> <p>The Responsible Entity has implemented</p> | <p>complete the removal within 24 hours of the termination action but did not initiate those removals for one individual, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for one individual, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p> | <p>complete the removal within 24 hours of the termination action but did not initiate those removals for two individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for two individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p> | <p>Information storage locations. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or complete the removal within 24 hours of the termination action but did not initiate those removals for three or more individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))  |  |  |   |
|-----|--------------|-----|---|--|--|---|
|     |              |     | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|     |              |     | <p>one or more process(es) to revoke the individual’s user accounts upon termination action but did not do so for within 30 calendar days of the date of termination action for one or more individuals, and did not identify, assess, and correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to</p> | <p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for two individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> | <p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for three or more individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> | <p>requires retention of access following reassignments or transfers but, for three or more individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |              |          |            |
|-----|--------------|-----|--|--------------|----------|------------|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL |
|     |              |     | change passwords for shared accounts known to the user upon termination action, reassignment, or transfer, but did not do so for within 30 calendar days of the date of termination action, reassignment, or transfer for one or more individuals, and did not identify, assess, and correct the deficiencies.<br>(5.5)<br><br>OR<br><br>The Responsible |              |          |            |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))   |              |          |            |
|-----|--------------|-----|--|--------------|----------|------------|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL |
|     |              |     | Entity has implemented one or more process(es) to determine and document extenuating operating circumstances following a termination action, reassignment, or transfer, but did not change one or more passwords for shared accounts known to the user within 10 calendar days following the end of the extenuating operating circumstances, and did not |              |          |            |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-004-5.1(X))               |              |          |            |
|-----|--------------|-----|--|--------------|----------|------------|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL |
|     |              |     | identify, assess, and correct the deficiencies.<br>(5.5) |              |          |            |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Guidelines and Technical Basis**

**Section 4 – Scope of Applicability of the CIP Cyber Security Standards**

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

**Requirement R1:**

The security awareness program is intended to be an informational program, not a formal training program. It should reinforce security practices to ensure that personnel maintain awareness of best practices for both physical and electronic security to protect its BES Cyber Systems. The Responsible Entity is not required to provide records that show that each individual received or understood the information, but they must maintain documentation of the program materials utilized in the form of posters, memos, and/or presentations.

Examples of possible mechanisms and evidence, when dated, which can be used are:

- Direct communications (e.g., emails, memos, computer based training, etc.);
- Indirect communications (e.g., posters, intranet, brochures, etc.);
- Management support and reinforcement (e.g., presentations, meetings, etc.).

### **Requirement R2:**

Training shall cover the policies, access controls, and procedures as developed for the BES Cyber Systems and include, at a minimum, the required items appropriate to personnel roles and responsibilities from Table R2. The Responsible Entity has the flexibility to define the training program and it may consist of multiple modules and multiple delivery mechanisms, but a single training program for all individuals needing to be trained is acceptable. The training can focus on functions, roles or responsibilities at the discretion of the Responsible Entity.

One new element in the training content is intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems as per FERC Order No. 706, Paragraph 434. This is not intended to provide technical training to individuals supporting networking hardware and software, but educating system users of the cyber security risks associated with the interconnectedness of these systems. The users, based on their function, role or responsibility, should have a basic understanding of which systems can be accessed from other systems and how the actions they take can affect cyber security.

Each Responsible Entity shall ensure all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, complete cyber security training prior to their being granted authorized access, except for CIP Exceptional Circumstances. To retain the authorized accesses, individuals must complete the training at least one every 15 months.

### **Requirement R3:**

Each Responsible Entity shall ensure a personnel risk assessment is performed for all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, prior to their being granted authorized access, except for program specified exceptional circumstances that are approved by the single senior management official or their delegate and impact the reliability of the BES or emergency response. Identity should be confirmed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. Identity only needs to be confirmed prior to initially granting access and only requires periodic confirmation according to the entity's process during the tenure of employment, which may or may not be the same as the initial verification action.

A seven year criminal history check should be performed for those locations where the individual has resided for at least six consecutive months. This check should also be performed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. When it is not possible to perform a full seven year criminal history check, documentation must be made of what criminal history check was performed, and the reasons a full seven-year check could not be performed. Examples of this could include



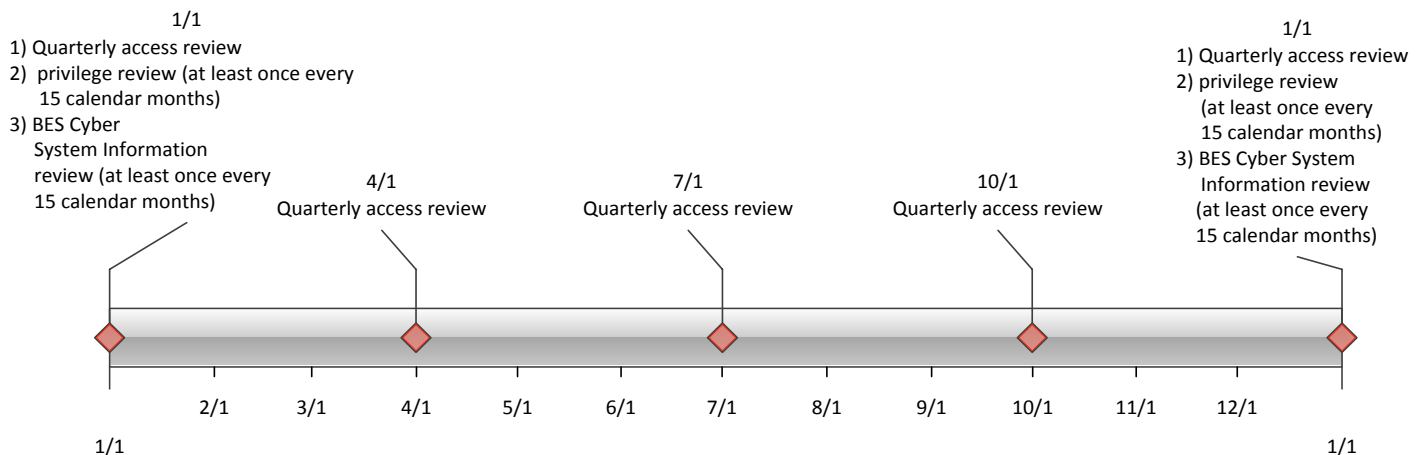
individuals under the age of 25 where a juvenile criminal history may be protected by law, individuals who may have resided in locations from where it is not possible to obtain a criminal history records check, violates the law or is not allowed under the existing collective bargaining agreement. The Responsible Entity should consider the absence of information for the full seven years when assessing the risk of granting access during the process to evaluate the criminal history check. There needs to be a personnel risk assessment that has been completed within the last seven years for each individual with access. A new criminal history records check must be performed as part of the new PRA. Individuals who have been granted access under a previous version of these standards need a new PRA within seven years of the date of their last PRA. The clarifications around the seven year criminal history check in this version do not require a new PRA be performed by the implementation date.

**Requirement R4:**

Authorization for electronic and unescorted physical access and access to BES Cyber System Information must be on the basis of necessity in the individual performing a work function. Documentation showing the authorization should have some justification of the business need included. To ensure proper segregation of duties, access authorization and provisioning should not be performed by the same person where possible.

This requirement specifies both quarterly reviews and reviews at least once every 15 calendar months. Quarterly reviews are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

The privilege review at least once every 15 calendar months is more detailed to ensure an individual’s associated privileges are the minimum necessary to perform their work function



(i.e., least privilege). Entities can more efficiently perform this review by implementing role-based access. This involves determining the specific roles on the system (e.g., system operator, technician, report viewer, administrator, etc.) then grouping access privileges to the role and assigning users to the role. Role-based access does not assume any specific software and can be implemented by defining specific provisioning processes for each role where access group assignments cannot be performed. Role-based access permissions eliminate the need to perform the privilege review on individual accounts. An example timeline of all the reviews in Requirement R4 is included below.

Separation of duties should be considered when performing the reviews in Requirement R4. The person reviewing should be different than the person provisioning access.

If the results of quarterly or at least once every 15 calendar months account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that this error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

**Requirement R5:**

The requirement to revoke access at the time of the termination action includes procedures showing revocation of access concurrent with the termination action. This requirement recognizes that the timing of the termination action may vary depending on the circumstance. Some common scenarios and possible processes on when the termination action occurs are provided in the following table. These scenarios are not an exhaustive list of all scenarios, but are representative of several routine business practices.

| Scenario   | Possible Process  |
|--|---|
| Immediate involuntary termination  | Human resources or corporate security escorts the individual off site and the supervisor or human resources personnel notify the appropriate personnel to begin the revocation process. |
| Scheduled involuntary termination  | Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.                          |
| Voluntary termination  | Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.                          |
| Retirement where the last working day is several weeks prior to the termination date | Human resources personnel coordinate with manager to determine the final date access is no longer needed and schedule the revocation of access on the determined day.                   |

|       |  |
|-------|--|
| Death | Human resources personnel are notified of the death and work with appropriate personnel to begin the revocation process. |
|-------|--|

Revocation of electronic access should be understood to mean a process with the end result that electronic access to BES Cyber Systems is no longer possible using credentials assigned to or known by the individual(s) whose access privileges are being revoked. Steps taken to accomplish this outcome may include deletion or deactivation of accounts used by the individual(s), but no specific actions are prescribed. Entities should consider the ramifications of deleting an account may include incomplete event log entries due to an unrecognized account or system services using the account to log on.

The initial revocation required in Requirement R5.1 includes unescorted physical access and Interactive Remote Access. These two actions should prevent any further access by the individual after termination. If an individual still has local access accounts (i.e., accounts on the Cyber Asset itself) on BES Cyber Assets, then the Responsible Entity has 30 days to complete the revocation process for those accounts. However, nothing prevents a Responsible Entity from performing all of the access revocation at the time of termination.

For transferred or reassigned individuals, a review of access privileges should be performed. This review could entail a simple listing of all authorizations for an individual and working with the respective managers to determine which access will still be needed in the new position. For instances in which the individual still needs to retain access as part of a transitory period, the entity should schedule a time to review these access privileges or include the privileges in the quarterly account review or annual privilege review.

Revocation of access to shared accounts is called out separately to prevent the situation where passwords on substation and generation devices are constantly changed due to staff turnover.

Requirement 5.5 specified that passwords for shared account are to be changed within 30 calendar days of the termination action or when the Responsible Entity determines an individual no longer requires access to the account as a result of a reassignment or transfer. The 30 days applies under normal operating conditions. However, circumstances may occur where this is not possible. Some systems may require an outage or reboot of the system in order to complete the password change. In periods of extreme heat or cold, many Responsible Entities may prohibit system outages and reboots in order to maintain reliability of the BES. When these circumstances occur, the Responsible Entity must document these circumstances and prepare to change the password within 10 calendar days following the end of the operating circumstances. Records of activities must be retained to show that the Responsible Entity followed the plan they created.



## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

Ensures that Responsible Entities with personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Assets take action so that those personnel with such authorized electronic or authorized unescorted physical access maintain awareness of the Responsible Entity's security practices.

**Summary of Changes:** Reformatted into table structure.

**Reference to prior version:** (Part 1.1) CIP-004-4, R1

**Change Rationale:** (Part 1.1)

*Changed to remove the need to ensure or prove everyone with authorized electronic or authorized unescorted physical access "received" ongoing reinforcement – to state that security awareness has been reinforced.*

*Moved example mechanisms to guidance.*

### **Rationale for R2:**

To ensure that the Responsible Entity's training program for personnel who need authorized electronic access and/or authorized unescorted physical access to BES Cyber Systems covers the proper policies, access controls, and procedures to protect BES Cyber Systems and are trained before access is authorized.

Based on their role, some personnel may not require training on all topics.

### **Summary of Changes:**

1. Addition of specific role training for:

- The visitor control program
- Electronic interconnectivity supporting the operation and control of BES Cyber Systems
- Storage media as part of the handling of BES Cyber Systems information

2. Change references from Critical Cyber Assets to BES Cyber Systems.

**Reference to prior version:** (Part 2.1) CIP004-4, R2.2.1

**Change Rationale:** (Part 2.1)

*Removed "proper use of Critical Cyber Assets" concept from previous versions to focus the requirement on cyber security issues, not the business function. The previous version was*

*focused more on the business or functional use of the BES Cyber System and is outside the scope of cyber security. Personnel who will administer the visitor control process or serve as escorts for visitors need training on the program. Core training on the handling of BES Cyber System (not Critical Cyber Assets) Information, with the addition of storage; FERC Order No. 706, paragraph 413 and paragraphs 632-634, 688, 732-734; DHS 2.4.16. Core training on the identification and reporting of a Cyber Security Incident; FERC Order No. 706, Paragraph 413; Related to CIP-008-5(X) & DHS Incident Reporting requirements for those with roles in incident reporting. Core training on the action plans and procedures to recover or re-establish BES Cyber Systems for personnel having a role in the recovery; FERC Order No. 706, Paragraph 413. Core training programs are intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems; FERC Order No. 706, Paragraph 434.*

**Reference to prior version:** (Part 2.2) CIP004-4, R2.1

**Change Rationale:** (Part 2.2)

*Addition of exceptional circumstances parameters as directed in FERC Order No. 706, Paragraph 431 is detailed in CIP-003-5(X).*

**Reference to prior version:** (Part 2.3) CIP004-4, R2.3

**Change Rationale:** (Part 2.3)

*Updated to replace “annually” with “once every 15 calendar months.”*

### **Rationale for R3:**

To ensure that individuals who need authorized electronic or authorized unescorted physical access to BES Cyber Systems have been assessed for risk. Whether initial access or maintaining access, those with access must have had a personnel risk assessment completed within the last 7 years.

**Summary of Changes:** Specify that the seven year criminal history check covers all locations where the individual has resided for six consecutive months or more, including current residence regardless of duration.

**Reference to prior version:** (Part 3.1) CIP004-4, R3.1

**Change Rationale:** (Part 3.1)

*Addressed interpretation request in guidance. Specified that process for identity confirmation is required. The implementation plan clarifies that a documented identity verification conducted under an earlier version of the CIP standards is sufficient.*

**Reference to prior version:** (Part 3.2) CIP004-4, R3.1

**Change Rationale:** (Part 3.2)

*Specify that the seven year criminal history check covers all locations where the individual has resided for six months or more, including current residence regardless of duration. Added*

*additional wording based on interpretation request. Provision is made for when a full seven-year check cannot be performed.*

**Reference to prior version:** (Part 3.3) New

**Change Rationale:** (Part 3.3)

*There should be documented criteria or a process used to evaluate criminal history records checks for authorizing access.*

**Reference to prior version:** (Part 3.4) CIP-004-4, R3.3

**Change Rationale:** (Part 3.4)

*Separated into its own table item.*

**Reference to prior version:** (Part 3.5) CIP-004-3, R3, R3.3

**Change Rationale:** (Part 3.5)

*Whether for initial access or maintaining access, establishes that those with access must have had PRA completed within 7 years. This covers both initial and renewal. The implementation plan specifies that initial performance of this requirement is 7 years after the last personnel risk assessment that was performed pursuant to a previous version of the CIP Cyber Security Standards for a personnel risk assessment. CIP-004-3, R3, R3.3*

#### **Rationale for R4:**

To ensure that individuals with access to BES Cyber Systems and the physical and electronic locations where BES Cyber System Information is stored by the Responsible Entity have been properly authorized for such access. "Authorization" should be considered to be a grant of permission by a person or persons empowered by the Responsible Entity to perform such grants and included in the delegations referenced in CIP-003-5(X). "Provisioning" should be considered the actions to provide access to an individual.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (i.e., physical access control system, remote access system, directory services).

CIP Exceptional Circumstances are defined in a Responsible Entity's policy from CIP-003-5(X) and allow an exception to the requirement for authorization to BES Cyber Systems and BES Cyber System Information.

Quarterly reviews in Part 4.5 are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to access the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account

databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

If the results of quarterly or annual account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that the error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

**Summary of Changes:** The primary change was in pulling the access management requirements from CIP-003-4, CIP-004-4, and CIP-007-4 into a single requirement. The requirements from Version 4 remain largely unchanged except to clarify some terminology. The purpose for combining these requirements is to remove the perceived redundancy in authorization and review. The requirement in CIP-004-4 R4 to maintain a list of authorized personnel has been removed because the list represents only one form of evidence to demonstrate compliance that only authorized persons have access.

**Reference to prior version:** (Part 4.1) CIP 003-4, R5.1 and R5.2; CIP-006-4, R1.5 and R4; CIP-007-4, R5.1 and R5.1.1

**Change Rationale:** (Part 4.1)

Combined requirements from CIP-003-4, CIP-007-4, and CIP-006-4 to make the authorization process clear and consistent. *CIP-003-4, CIP-004-4, CIP-006-4, and CIP-007-4 all reference authorization of access in some form, and CIP-003-4 and CIP-007-4 require authorization on a “need to know” basis or with respect to work functions performed. These were consolidated to ensure consistency in the requirement language.*

**Reference to prior version:** (Part 4.2) CIP 004-4, R4.1

**Change Rationale:** (Part 4.2)

*Feedback among team members, observers, and regional CIP auditors indicates there has been confusion in implementation around what the term “review” entailed in CIP-004-4, Requirement R4.1. This requirement clarifies the review should occur between the provisioned access and authorized access.*

**Reference to prior version:** (Part 4.3) CIP 007-4, R5.1.3

**Change Rationale:** (Part 4.3)

*Moved requirements to ensure consistency and eliminate the cross-referencing of requirements. Clarified what was necessary in performing verification by stating the objective was to confirm that access privileges are correct and the minimum necessary.*

**Reference to prior version:** (Part 4.4) CIP-003-4, R5.1.2

**Change Rationale:** (Part 4.4)

*Moved requirement to ensure consistency among access reviews. Clarified precise meaning of annual. Clarified what was necessary in performing a verification by stating the objective was to*



*confirm access privileges are correct and the minimum necessary for performing assigned work functions.*

**Rationale for R5:**

The timely revocation of electronic access to BES Cyber Systems is an essential element of an access management regime. When an individual no longer requires access to a BES Cyber System to perform his or her assigned functions, that access should be revoked. This is of particular importance in situations where a change of assignment or employment is involuntary, as there is a risk the individual(s) involved will react in a hostile or destructive manner.

In considering how to address directives in FERC Order No. 706 directing “immediate” revocation of access for involuntary separation, the SDT chose not to specify hourly time parameters in the requirement (e.g., revoking access within 1 hour). The point in time at which an organization terminates a person cannot generally be determined down to the hour. However, most organizations have formal termination processes, and the timeliest revocation of access occurs in concurrence with the initial processes of termination.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (e.g., physical access control system, remote access system, directory services).

**Summary of Changes:** FERC Order No. 706, Paragraphs 460 and 461, state the following: “The Commission adopts the CIP NOPR proposal to direct the ERO to develop modifications to CIP-004-1 to require immediate revocation of access privileges when an employee, contractor or vendor no longer performs a function that requires physical or electronic access to a Critical Cyber Asset for any reason (including disciplinary action, transfer, retirement, or termination).

As a general matter, the Commission believes that revoking access when an employee no longer needs it, either because of a change in job or the end of employment, must be immediate.”

**Reference to prior version:** (Part 5.1) CIP 004-4, R4.2

**Change Rationale:** (Part 5.1)

*The FERC Order No. 706, Paragraphs 460 and 461, directs modifications to the Standards to **require immediate revocation** for any person no longer needing access. To address this directive, this requirement specifies revocation concurrent with the termination instead of within 24 hours.*

**Reference to prior version:** (Part 5.2) CIP-004-4, R4.2

**Change Rationale:** (Part 5.2)

*FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access, including transferred employees. In reviewing how to modify this requirement, the SDT determined the date a person no longer needs access after a transfer was problematic because the need may change over time. As a result, the SDT adapted this requirement from NIST 800-53 Version 3 to review access authorizations on the date of the transfer. The SDT felt this was a more effective control in accomplishing the objective to prevent a person from accumulating unnecessary authorizations through transfers.*

**Reference to prior version:** (Part 5.3) New

**Change Rationale:** (Part 5.3)

*FERC Order No. 706, Paragraph 386, directs modifications to the standards to require prompt revocation of access to protected information. To address this directive, Responsible Entities are required to revoke access to areas designated for BES Cyber System Information. This could include records closets, substation control houses, records management systems, file shares or other physical and logical areas under the Responsible Entity's control.*

**Reference to prior version:** (Part 5.4) New

**Change Rationale:** (Part 5.4)

*FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access. In order to meet the immediate timeframe, Responsible Entities will likely have initial revocation procedures to prevent remote and physical access to the BES Cyber System. Some cases may take more time to coordinate access revocation on individual Cyber Assets and applications without affecting reliability. This requirement provides the additional time to review and complete the revocation process. Although the initial actions already prevent further access, this step provides additional assurance in the access revocation process.*

**Reference to prior version:** (Part 5.5) CIP-007-4, R5.2.3

**Change Rationale:** (Part 5.5)

*To provide clarification of expected actions in managing the passwords.*

## Version History

| Version | Date     | Action   | Change Tracking   |
|---------|----------|--|---|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”  | 3/24/06   |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3       | 12/16/09 | Updated version number from -2 to -3<br>Approved by the NERC Board of Trustees.  |   |
| 3       | 3/31/10  | Approved by FERC.  |   |
| 4       | 12/30/10 | Modified to add specific criteria for Critical Asset identification.   | Update  |
| 4       | 1/24/11  | Approved by the NERC Board of Trustees.  | Update  |
| 5       | 11/26/12 | Adopted by the NERC Board of Trustees.   | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |
| 5.1     | 9/30/13  | Modified two VSLs in R4.   | Errata  |
| 5.1     | 11/22/13 | FERC Order issued approving CIP-004-5.1. (Order becomes effective on 2/3/14.)  |   |
| 5.1     | 4/2/14   | Address FERC Order 791 directive to modify Requirement R4 VRF and VSLs   | R4-VRF and VSLs   |

Guidelines and Technical Basis

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|               |            |  |   |
|---------------|------------|--|---|
| 5.1           | 5/6/14     | The NERC Board of Trustees adopted a revision to the VRF of Requirement 4 from Lower to Medium in CIP-004-5.1. |   |
| <u>5.1(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)
2. **Number:** CIP-005-5(X)
3. **Purpose:** To manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**

#### **4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-005-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-005-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-005-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-005-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **High Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to high impact BES Cyber Systems with Dial-up Connectivity.
- **High Impact BES Cyber Systems with External Routable Connectivity** – Only applies to high impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Medium Impact BES Cyber Systems** – Applies to each BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.



- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to medium impact BES Cyber Systems with Dial-up Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Electronic Access Points (EAP)** – Applies at Electronic Access Points associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

**B. Requirements and Measures**

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-5(X) Table R1 – Electronic Security Perimeter*. *[Violation Risk Factor: Medium]* *[Time Horizon: Operations Planning and Same Day Operations]*.
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-005-5(X) Table R1 – Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-005-5(X) Table R1 – Electronic Security Perimeter |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 1.1   | High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> <li>• PCA</li> </ul><br>Medium Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> <li>• PCA</li> </ul> | All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined ESP. | An example of evidence may include, but is not limited to, a list of all ESPs with all uniquely identifiable applicable Cyber Assets connected via a routable protocol within each ESP. |

| CIP-005-5(X) Table R1 – Electronic Security Perimeter |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 1.2   | <p>High Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | All External Routable Connectivity must be through an identified Electronic Access Point (EAP). | An example of evidence may include, but is not limited to, network diagrams showing all external routable communication paths and the identified EAPs. |

| CIP-005-5(X) Table R1 – Electronic Security Perimeter |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 1.3   | <p>Electronic Access Points for High Impact BES Cyber Systems</p> <p>Electronic Access Points for Medium Impact BES Cyber Systems</p>   | <p>Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.</p> | <p>An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.</p> |
| 1.4   | <p>High Impact BES Cyber Systems with Dial-up Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>Where technically feasible, perform authentication when establishing Dial-up Connectivity with applicable Cyber Assets.</p>          | <p>An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.</p>                                |

| CIP-005-5(X) Table R1 – Electronic Security Perimeter |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 1.5   | Electronic Access Points for High Impact BES Cyber Systems<br><br>Electronic Access Points for Medium Impact BES Cyber Systems at Control Centers | Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications. | An example of evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, etc.) are implemented. |

- R2.** Each Responsible Entity allowing Interactive Remote Access to BES Cyber Systems shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-5(X) Table R2 – Interactive Remote Access Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M2.** Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-5(X) Table R2 – Interactive Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-005-5(X) Table R2 – Interactive Remote Access Management |   |  |   |
|--|---|--|---|
| Part   | Applicable Systems  | Requirements   | Measures  |
| 2.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>Utilize an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.</p> | <p>Examples of evidence may include, but are not limited to, network diagrams or architecture documents.</p>                                  |
| 2.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>For all Interactive Remote Access sessions, utilize encryption that terminates at an Intermediate System.</p>   | <p>An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.</p> |

| CIP-005-5(X) Table R2 – Interactive Remote Access Management |   |  |   |
|--|---|--|---|
| Part   | Applicable Systems  | Requirements   | Measures  |
| 2.3  | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>Require multi-factor authentication for all Interactive Remote Access sessions.</p> | <p>An example of evidence may include, but is not limited to, architecture documents detailing the authentication factors used.</p> <p>Examples of authenticators may include, but are not limited to,</p> <ul style="list-style-type: none"> <li>• Something the individual knows such as passwords or PINs. This does not include User ID;</li> <li>• Something the individual has such as tokens, digital certificates, or smart cards; or</li> <li>• Something the individual is such as fingerprints, iris scans, or other biometric characteristics.</li> </ul> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None



2. Table of Compliance Elements

| R # | Time Horizon                                | VRF    | Violation Severity Levels (CIP-005-5(X)) |              |   |  |
|-----|---|--------|--|--------------|---|--|
|     |   |        | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
| R1  | Operations Planning and Same Day Operations | Medium |  |              | The Responsible Entity did not have a method for detecting malicious communications for both inbound and outbound communications. (1.5) | The Responsible Entity did not document one or more processes for CIP-005-5(X) Table R1 – Electronic Security Perimeter. (R1)<br>OR<br>The Responsible Entity did not have all applicable Cyber Assets connected to a network via a routable protocol within a defined Electronic Security Perimeter (ESP). (1.1)<br>OR<br>External Routable Connectivity through the ESP was not through an identified EAP. (1.2)<br>OR<br>The Responsible Entity did not require inbound and |

| R #       | Time Horizon                                       | VRF           | Violation Severity Levels (CIP-005-5(X))   |   |   |   |
|-----------|--|---------------|--|---|---|---|
|           |  |               | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|           |  |               |  |   |   | outbound access permissions and deny all other access by default. (1.3)<br>OR<br>The Responsible Entity did not perform authentication when establishing dial-up connectivity with the applicable Cyber Assets, where technically feasible. (1.4) |
| <b>R2</b> | <b>Operations Planning and Same Day Operations</b> | <b>Medium</b> | The Responsible Entity does not have documented processes for one or more of the applicable items for Requirement Parts 2.1 through 2.3. | The Responsible Entity did not implement processes for one of the applicable items for Requirement Parts 2.1 through 2.3. | The Responsible Entity did not implement processes for two of the applicable items for Requirement Parts 2.1 through 2.3. | The Responsible Entity did not implement processes for three of the applicable items for Requirement Parts 2.1 through 2.3.   |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Guidelines and Technical Basis**

**Section 4 – Scope of Applicability of the CIP Cyber Security Standards**

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

**Requirement R1:**

CIP-005-5(X), Requirement R1 requires segmenting of BES Cyber Systems from other systems of differing trust levels by requiring controlled Electronic Access Points between the different trust zones. Electronic Security Perimeters are also used as a primary defense layer for some BES Cyber Systems that may not inherently have sufficient cyber security functionality, such as devices that lack authentication capability.

All applicable BES Cyber Systems that are connected to a network via a routable protocol must have a defined Electronic Security Perimeter (ESP). Even standalone networks that have no external connectivity to other networks must have a defined ESP. The ESP defines a zone of protection around the BES Cyber System, and it also provides clarity for entities to determine what systems or Cyber Assets are in scope and what requirements they must meet. The ESP is used in:

- Defining the scope of ‘Associated Protected Cyber Assets’ that must also meet certain CIP requirements.
- Defining the boundary in which all of the Cyber Assets must meet the requirements of the highest impact BES Cyber System that is in the zone (the ‘high water mark’).

The CIP Cyber Security Standards do not require network segmentation of BES Cyber Systems by impact classification. Many different impact classifications can be mixed within an ESP. However, all of the Cyber Assets and BES Cyber Systems within the ESP must be protected at the level of the highest impact BES Cyber System present in the ESP (i.e., the “high water mark”) where the term “Protected Cyber Assets” is used. The CIP Cyber Security Standards accomplish the “high water mark” by associating all other Cyber Assets within the ESP, even other BES Cyber Systems of lesser impact, as “Protected Cyber Assets” of the highest impact system in the ESP.

For example, if an ESP contains both a high impact BES Cyber System and a low impact BES Cyber System, each Cyber Asset of the low impact BES Cyber System is an “Associated Protected Cyber Asset” of the high impact BES Cyber System and must meet all requirements with that designation in the applicability columns of the requirement tables.

If there is routable connectivity across the ESP into any Cyber Asset, then an Electronic Access Point (EAP) must control traffic into and out of the ESP. Responsible Entities should know what traffic needs to cross an EAP and document those reasons to ensure the EAPs limit the traffic to only those known communication needs. These include, but are not limited to, communications needed for normal operations, emergency operations, support, maintenance, and troubleshooting.

The EAP should control both inbound and outbound traffic. The standard added outbound traffic control, as it is a prime indicator of compromise and a first level of defense against zero day vulnerability-based attacks. If Cyber Assets within the ESP become compromised and attempt to communicate to unknown hosts outside the ESP (usually ‘command and control’ hosts on the Internet, or compromised ‘jump hosts’ within the Responsible Entity’s other networks acting as intermediaries), the EAPs should function as a first level of defense in stopping the exploit. This does not limit the Responsible Entity from controlling outbound traffic at the level of granularity that it deems appropriate, and large ranges of internal addresses may be allowed. The SDT’s intent is that the Responsible Entity knows what other Cyber Assets or ranges of addresses a BES Cyber System needs to communicate with and limits the communications to that known range. For example, most BES Cyber Systems within a Responsible Entity should not have the ability to communicate through an EAP to any network address in the world, but should probably be at least limited to the address space of the

Responsible Entity, and preferably to individual subnet ranges or individual hosts within the Responsible Entity's address space. The SDT's intent is not for Responsible Entities to document the inner workings of stateful firewalls, where connections initiated in one direction are allowed a return path. The intent is to know and document what systems can talk to what other systems or ranges of systems on the other side of the EAP, such that rogue connections can be detected and blocked.

This requirement applies only to communications for which access lists and 'deny by default' type requirements can be universally applied, which today are those that employ routable protocols. Direct serial, non-routable connections are not included as there is no perimeter or firewall type security that should be universally mandated across all entities and all serial communication situations. There is no firewall or perimeter capability for an RS232 cable run between two Cyber Assets. Without a clear 'perimeter type' security control that can be applied in practically every circumstance, such a requirement would mostly generate technical feasibility exceptions ("TFEs") rather than increased security.

As for dial-up connectivity, the Standard Drafting Team's intent of this requirement is to prevent situations where only a phone number can establish direct connectivity to the BES Cyber Asset. If a dial-up modem is implemented in such a way that it simply answers the phone and connects the line to the BES Cyber Asset with no authentication of the calling party, it is a vulnerability to the BES Cyber System. The requirement calls for some form of authentication of the calling party before completing the connection to the BES Cyber System. Some examples of acceptable methods include dial-back modems, modems that must be remotely enabled or powered up, and modems that are only powered on by onsite personnel when needed along with policy that states they are disabled after use. If the dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.

The standard adds a requirement to detect malicious communications for Control Centers. This is in response to FERC Order No. 706, Paragraphs 496-503, where ESPs are required to have two distinct security measures such that the BES Cyber Systems do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear that this is not simply redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs. Technologies meeting this requirement include Intrusion Detection or Intrusion Prevention Systems (IDS/IPS) or other forms of deep packet inspection. These technologies go beyond source/destination/port rule sets and thus provide another distinct security measure at the ESP.

### **Requirement R2:**

See Secure Remote Access Reference Document (see remote access alert).

## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

The Electronic Security Perimeter (“ESP”) serves to control traffic at the external electronic boundary of the BES Cyber System. It provides a first layer of defense for network based attacks as it limits reconnaissance of targets, restricts and prohibits traffic to a specified rule set, and assists in containing any successful attacks.

**Summary of Changes:** CIP-005, Requirement R1 has taken more of a focus on the discrete Electronic Access Points, rather than the logical “perimeter.”

CIP-005 (V1 through V4), Requirement R1.2 has been deleted from V5. This requirement was definitional in nature and used to bring dial-up modems using non-routable protocols into the scope of CIP-005. The non-routable protocol exclusion no longer exists as a blanket CIP-002 filter for applicability in V5, therefore there is no need for this requirement.

CIP-005 (V1 through V4), Requirement R1.1 and R1.3 were also definitional in nature and have been deleted from V5 as separate requirements but the concepts were integrated into the definitions of ESP and Electronic Access Point (“EAP”).

**Reference to prior version:** (Part 1.1) CIP-005-4, R1

**Change Rationale:** (Part 1.1)

*Explicitly clarifies that BES Cyber Assets connected via routable protocol must be in an Electronic Security Perimeter.*

**Reference to prior version:** (Part 1.2) CIP-005-4, R1

**Change Rationale:** (Part 1.2)

*Changed to refer to the defined term Electronic Access Point and BES Cyber System.*

**Reference to prior version:** (Part 1.3) CIP-005-4, R2.1

**Change Rationale:** (Part 1.3)

*Changed to refer to the defined term Electronic Access Point and to focus on the entity knowing and having a reason for what it allows through the EAP in both inbound and outbound directions.*

**Reference to prior version:** (Part 1.4) CIP-005-4, R2.3

**Change Rationale:** (Part 1.4)

*Added clarification that dial-up connectivity should perform authentication so that the BES Cyber System is not directly accessible with a phone number only.*

**Reference to prior version:** (Part 1.5) CIP-005-4, R1

**Change Rationale:** (Part 1.5)

*Per FERC Order No. 706, Paragraphs 496-503, ESPs need two distinct security measures such that the Cyber Assets do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear this is not simple redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs.*

**Rationale for R2:**

Registered Entities use Interactive Remote Access to access Cyber Assets to support and maintain control systems networks. Discovery and announcement of vulnerabilities for remote access methods and technologies, that were previously thought secure and in use by a number of electric sector entities, necessitate changes to industry security control standards. Currently, no requirements are in effect for management of secure remote access to Cyber Assets to be afforded the NERC CIP protective measures. Inadequate safeguards for remote access can allow unauthorized access to the organization's network, with potentially serious consequences. Additional information is provided in **Guidance for Secure Interactive Remote Access** published by NERC in July 2011.

Remote access control procedures must provide adequate safeguards through robust identification, authentication and encryption techniques. Remote access to the organization's network and resources will only be permitted providing that authorized users are authenticated, data is encrypted across the network, and privileges are restricted.

The Intermediate System serves as a proxy for the remote user. Rather than allowing all the protocols the user might need to access Cyber Assets inside the Electronic Security Perimeter to traverse from the Electronic Security Perimeter to the remote computer, only the protocol required for remotely controlling the jump host is required. This allows the firewall rules to be much more restrictive than if the remote computer was allowed to connect to Cyber Assets within the Electronic Security Perimeter directly. The use of an Intermediate System also protects the Cyber Asset from vulnerabilities on the remote computer.

The use of multi-factor authentication provides an added layer of security. Passwords can be guessed, stolen, hijacked, found, or given away. They are subject to automated attacks including brute force attacks, in which possible passwords are tried until the password is found, or dictionary attacks, where words and word combinations are tested as possible passwords. But if a password or PIN must be supplied along with a one-time password supplied by a token, a fingerprint, or some other factor, the password is of no value unless the other factor(s) used for authentication are acquired along with it.

Encryption is used to protect the data that is sent between the remote computer and the Intermediate System. Data encryption is important for anyone who wants or needs secure data transfer. Encryption is needed when there is a risk of unauthorized interception of transmissions on the communications link. This is especially important when using the Internet as the communication means.

**Summary of Changes:** This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

**Reference to prior version:** (Part 2.1) New

**Change Rationale:** (Part 2.1)

*This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.*

**Reference to prior version:** (Part 2.2) CIP-007-5(X), R3.1

**Change Rationale:** (Part 2.2)

*This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The purpose of this part is to protect the confidentiality and integrity of each Interactive Remote Access session.*

**Reference to prior version:** (Part 2.3) CIP-007-5(X), R3.2

**Change Rationale:** (Part 2.3)

*This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The multi-factor authentication methods are also the same as those identified in the Homeland Security Presidential Directive 12 (HSPD-12), issued August 12, 2007.*



## Version History

| Version | Date     | Action   | Change Tracking   |
|---------|----------|--|---|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”  | 3/24/06   |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3       | 12/16/09 | Updated version number from -2 to -3<br>Approved by the NERC Board of Trustees.  |   |
| 3       | 3/31/10  | Approved by FERC.  |   |
| 4       | 12/30/10 | Modified to add specific criteria for Critical Asset identification.   | Update  |
| 4       | 1/24/11  | Approved by the NERC Board of Trustees.  | Update  |
| 5       | 11/26/12 | Adopted by the NERC Board of Trustees.   | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |
| 5       | 11/22/13 | FERC Order issued approving CIP-005-5. (Order becomes effective on 2/3/14.)  |   |
| 5(X)    | TBD      | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial                    |

|  |  |  |                       |
|--|--|--|-----------------------|
|  |  |  | Action Scheme and RAS |
|--|--|--|-----------------------|

## A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)
2. **Number:** CIP-005-5(X)
3. **Purpose:** To manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**

#### 4.1.8 Transmission Owner

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-005-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-005-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-005-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-005-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **High Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to high impact BES Cyber Systems with Dial-up Connectivity.
- **High Impact BES Cyber Systems with External Routable Connectivity** – Only applies to high impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Medium Impact BES Cyber Systems** – Applies to each BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to medium impact BES Cyber Systems with Dial-up Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Electronic Access Points (EAP)** – Applies at Electronic Access Points associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

**B. Requirements and Measures**

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-5(X) Table R1 – Electronic Security Perimeter*. *[Violation Risk Factor: Medium]* *[Time Horizon: Operations Planning and Same Day Operations]*.
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-005-5(X) Table R1 – Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-005-5(X) Table R1 – Electronic Security Perimeter |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 1.1   | High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> <li>• PCA</li> </ul><br>Medium Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> <li>• PCA</li> </ul> | All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined ESP. | An example of evidence may include, but is not limited to, a list of all ESPs with all uniquely identifiable applicable Cyber Assets connected via a routable protocol within each ESP. |



**CIP-005-5(X) Table R1 – Electronic Security Perimeter**

| Part | Applicable Systems  | Requirements   | Measures  |
|------|---|--|---|
| 1.2  | <p>High Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>All External Routable Connectivity must be through an identified Electronic Access Point (EAP).</p> | <p>An example of evidence may include, but is not limited to, network diagrams showing all external routable communication paths and the identified EAPs.</p> |

CIP-005-5(X) Table R1 – Electronic Security Perimeter

| Part | Applicable Systems   | Requirements   | Measures  |
|------|--|--|---|
| 1.3  | Electronic Access Points for High Impact BES Cyber Systems<br><br>Electronic Access Points for Medium Impact BES Cyber Systems   | Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default. | An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason. |
| 1.4  | High Impact BES Cyber Systems with Dial-up Connectivity and their associated: <ul style="list-style-type: none"> <li>• PCA</li> </ul><br>Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated: <ul style="list-style-type: none"> <li>• PCA</li> </ul> | Where technically feasible, perform authentication when establishing Dial-up Connectivity with applicable Cyber Assets.          | An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.                                |

| CIP-005-5(X) Table R1 – Electronic Security Perimeter |  |   |  |
|---|--|---|--|
| Part  | Applicable Systems   | Requirements  | Measures   |
| 1.5   | <p>Electronic Access Points for High Impact BES Cyber Systems</p> <p>Electronic Access Points for Medium Impact BES Cyber Systems at Control Centers</p> | <p>Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.</p> | <p>An example of evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, etc.) are implemented.</p> |

- R2.** Each Responsible Entity allowing Interactive Remote Access to BES Cyber Systems shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-5(X) Table R2 – Interactive Remote Access Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M2.** Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-5(X) Table R2 – Interactive Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-005-5(X) Table R2 – Interactive Remote Access Management |   |  |   |
|--|---|--|---|
| Part   | Applicable Systems  | Requirements   | Measures  |
| 2.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>Utilize an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.</p> | <p>Examples of evidence may include, but are not limited to, network diagrams or architecture documents.</p>                                  |
| 2.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>For all Interactive Remote Access sessions, utilize encryption that terminates at an Intermediate System.</p>   | <p>An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.</p> |

| CIP-005-5(X) Table R2 – Interactive Remote Access Management |   |  |   |
|--|---|--|---|
| Part   | Applicable Systems  | Requirements   | Measures  |
| 2.3  | <p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> <li>• PCA</li> </ul> | <p>Require multi-factor authentication for all Interactive Remote Access sessions.</p> | <p>An example of evidence may include, but is not limited to, architecture documents detailing the authentication factors used.</p> <p>Examples of authenticators may include, but are not limited to,</p> <ul style="list-style-type: none"> <li>• Something the individual knows such as passwords or PINs. This does not include User ID;</li> <li>• Something the individual has such as tokens, digital certificates, or smart cards; or</li> <li>• Something the individual is such as fingerprints, iris scans, or other biometric characteristics.</li> </ul> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon                                | VRF    | Violation Severity Levels (CIP-005-5(X)) |              |   |   |
|-----|---|--------|--|--------------|---|---|
|     |   |        | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
| R1  | Operations Planning and Same Day Operations | Medium |  |              | The Responsible Entity did not have a method for detecting malicious communications for both inbound and outbound communications. (1.5) | <p>The Responsible Entity did not document one or more processes for CIP-005-5(X) Table R1 – Electronic Security Perimeter. (R1)</p> <p>OR</p> <p>The Responsible Entity did not have all applicable Cyber Assets connected to a network via a routable protocol within a defined Electronic Security Perimeter (ESP). (1.1)</p> <p>OR</p> <p>External Routable Connectivity through the ESP was not through an identified EAP. (1.2)</p> <p>OR</p> <p>The Responsible Entity did not require inbound and</p> |

| R #       | Time Horizon                                       | VRF           | Violation Severity Levels (CIP-005-5(X))   |   |   |   |
|-----------|--|---------------|--|---|---|---|
|           |  |               | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|           |  |               |  |   |   | outbound access permissions and deny all other access by default. (1.3)<br>OR<br>The Responsible Entity did not perform authentication when establishing dial-up connectivity with the applicable Cyber Assets, where technically feasible. (1.4) |
| <b>R2</b> | <b>Operations Planning and Same Day Operations</b> | <b>Medium</b> | The Responsible Entity does not have documented processes for one or more of the applicable items for Requirement Parts 2.1 through 2.3. | The Responsible Entity did not implement processes for one of the applicable items for Requirement Parts 2.1 through 2.3. | The Responsible Entity did not implement processes for two of the applicable items for Requirement Parts 2.1 through 2.3. | The Responsible Entity did not implement processes for three of the applicable items for Requirement Parts 2.1 through 2.3.   |



**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**Guidelines and Technical Basis**

**Section 4 – Scope of Applicability of the CIP Cyber Security Standards**

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

**Requirement R1:**

CIP-005-5(X), Requirement R1 requires segmenting of BES Cyber Systems from other systems of differing trust levels by requiring controlled Electronic Access Points between the different trust zones. Electronic Security Perimeters are also used as a primary defense layer for some BES Cyber Systems that may not inherently have sufficient cyber security functionality, such as devices that lack authentication capability.

All applicable BES Cyber Systems that are connected to a network via a routable protocol must have a defined Electronic Security Perimeter (ESP). Even standalone networks that have no external connectivity to other networks must have a defined ESP. The ESP defines a zone of protection around the BES Cyber System, and it also provides clarity for entities to determine what systems or Cyber Assets are in scope and what requirements they must meet. The ESP is used in:

- Defining the scope of ‘Associated Protected Cyber Assets’ that must also meet certain CIP requirements.
- Defining the boundary in which all of the Cyber Assets must meet the requirements of the highest impact BES Cyber System that is in the zone (the ‘high water mark’).

The CIP Cyber Security Standards do not require network segmentation of BES Cyber Systems by impact classification. Many different impact classifications can be mixed within an ESP. However, all of the Cyber Assets and BES Cyber Systems within the ESP must be protected at the level of the highest impact BES Cyber System present in the ESP (i.e., the “high water mark”) where the term “Protected Cyber Assets” is used. The CIP Cyber Security Standards accomplish the “high water mark” by associating all other Cyber Assets within the ESP, even other BES Cyber Systems of lesser impact, as “Protected Cyber Assets” of the highest impact system in the ESP.

For example, if an ESP contains both a high impact BES Cyber System and a low impact BES Cyber System, each Cyber Asset of the low impact BES Cyber System is an “Associated Protected Cyber Asset” of the high impact BES Cyber System and must meet all requirements with that designation in the applicability columns of the requirement tables.

If there is routable connectivity across the ESP into any Cyber Asset, then an Electronic Access Point (EAP) must control traffic into and out of the ESP. Responsible Entities should know what traffic needs to cross an EAP and document those reasons to ensure the EAPs limit the traffic to only those known communication needs. These include, but are not limited to, communications needed for normal operations, emergency operations, support, maintenance, and troubleshooting.

The EAP should control both inbound and outbound traffic. The standard added outbound traffic control, as it is a prime indicator of compromise and a first level of defense against zero day vulnerability-based attacks. If Cyber Assets within the ESP become compromised and attempt to communicate to unknown hosts outside the ESP (usually ‘command and control’ hosts on the Internet, or compromised ‘jump hosts’ within the Responsible Entity’s other networks acting as intermediaries), the EAPs should function as a first level of defense in stopping the exploit. This does not limit the Responsible Entity from controlling outbound traffic at the level of granularity that it deems appropriate, and large ranges of internal addresses may be allowed. The SDT’s intent is that the Responsible Entity knows what other Cyber Assets or ranges of addresses a BES Cyber System needs to communicate with and limits the communications to that known range. For example, most BES Cyber Systems within a Responsible Entity should not have the ability to communicate through an EAP to any network address in the world, but should probably be at least limited to the address space of the

Responsible Entity, and preferably to individual subnet ranges or individual hosts within the Responsible Entity's address space. The SDT's intent is not for Responsible Entities to document the inner workings of stateful firewalls, where connections initiated in one direction are allowed a return path. The intent is to know and document what systems can talk to what other systems or ranges of systems on the other side of the EAP, such that rogue connections can be detected and blocked.

This requirement applies only to communications for which access lists and 'deny by default' type requirements can be universally applied, which today are those that employ routable protocols. Direct serial, non-routable connections are not included as there is no perimeter or firewall type security that should be universally mandated across all entities and all serial communication situations. There is no firewall or perimeter capability for an RS232 cable run between two Cyber Assets. Without a clear 'perimeter type' security control that can be applied in practically every circumstance, such a requirement would mostly generate technical feasibility exceptions ("TFEs") rather than increased security.

As for dial-up connectivity, the Standard Drafting Team's intent of this requirement is to prevent situations where only a phone number can establish direct connectivity to the BES Cyber Asset. If a dial-up modem is implemented in such a way that it simply answers the phone and connects the line to the BES Cyber Asset with no authentication of the calling party, it is a vulnerability to the BES Cyber System. The requirement calls for some form of authentication of the calling party before completing the connection to the BES Cyber System. Some examples of acceptable methods include dial-back modems, modems that must be remotely enabled or powered up, and modems that are only powered on by onsite personnel when needed along with policy that states they are disabled after use. If the dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.

The standard adds a requirement to detect malicious communications for Control Centers. This is in response to FERC Order No. 706, Paragraphs 496-503, where ESPs are required to have two distinct security measures such that the BES Cyber Systems do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear that this is not simply redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs. Technologies meeting this requirement include Intrusion Detection or Intrusion Prevention Systems (IDS/IPS) or other forms of deep packet inspection. These technologies go beyond source/destination/port rule sets and thus provide another distinct security measure at the ESP.

### **Requirement R2:**

See Secure Remote Access Reference Document (see remote access alert).

## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

The Electronic Security Perimeter (“ESP”) serves to control traffic at the external electronic boundary of the BES Cyber System. It provides a first layer of defense for network based attacks as it limits reconnaissance of targets, restricts and prohibits traffic to a specified rule set, and assists in containing any successful attacks.

**Summary of Changes:** CIP-005, Requirement R1 has taken more of a focus on the discrete Electronic Access Points, rather than the logical “perimeter.”

CIP-005 (V1 through V4), Requirement R1.2 has been deleted from V5. This requirement was definitional in nature and used to bring dial-up modems using non-routable protocols into the scope of CIP-005. The non-routable protocol exclusion no longer exists as a blanket CIP-002 filter for applicability in V5, therefore there is no need for this requirement.

CIP-005 (V1 through V4), Requirement R1.1 and R1.3 were also definitional in nature and have been deleted from V5 as separate requirements but the concepts were integrated into the definitions of ESP and Electronic Access Point (“EAP”).

**Reference to prior version:** (Part 1.1) CIP-005-4, R1

**Change Rationale:** (Part 1.1)

*Explicitly clarifies that BES Cyber Assets connected via routable protocol must be in an Electronic Security Perimeter.*

**Reference to prior version:** (Part 1.2) CIP-005-4, R1

**Change Rationale:** (Part 1.2)

*Changed to refer to the defined term Electronic Access Point and BES Cyber System.*

**Reference to prior version:** (Part 1.3) CIP-005-4, R2.1

**Change Rationale:** (Part 1.3)

*Changed to refer to the defined term Electronic Access Point and to focus on the entity knowing and having a reason for what it allows through the EAP in both inbound and outbound directions.*

**Reference to prior version:** (Part 1.4) CIP-005-4, R2.3

**Change Rationale:** (Part 1.4)

*Added clarification that dial-up connectivity should perform authentication so that the BES Cyber System is not directly accessible with a phone number only.*

**Reference to prior version:** (Part 1.5) CIP-005-4, R1

**Change Rationale:** (Part 1.5)

*Per FERC Order No. 706, Paragraphs 496-503, ESPs need two distinct security measures such that the Cyber Assets do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear this is not simple redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs.*

**Rationale for R2:**

Registered Entities use Interactive Remote Access to access Cyber Assets to support and maintain control systems networks. Discovery and announcement of vulnerabilities for remote access methods and technologies, that were previously thought secure and in use by a number of electric sector entities, necessitate changes to industry security control standards. Currently, no requirements are in effect for management of secure remote access to Cyber Assets to be afforded the NERC CIP protective measures. Inadequate safeguards for remote access can allow unauthorized access to the organization's network, with potentially serious consequences. Additional information is provided in **Guidance for Secure Interactive Remote Access** published by NERC in July 2011.

Remote access control procedures must provide adequate safeguards through robust identification, authentication and encryption techniques. Remote access to the organization's network and resources will only be permitted providing that authorized users are authenticated, data is encrypted across the network, and privileges are restricted.

The Intermediate System serves as a proxy for the remote user. Rather than allowing all the protocols the user might need to access Cyber Assets inside the Electronic Security Perimeter to traverse from the Electronic Security Perimeter to the remote computer, only the protocol required for remotely controlling the jump host is required. This allows the firewall rules to be much more restrictive than if the remote computer was allowed to connect to Cyber Assets within the Electronic Security Perimeter directly. The use of an Intermediate System also protects the Cyber Asset from vulnerabilities on the remote computer.

The use of multi-factor authentication provides an added layer of security. Passwords can be guessed, stolen, hijacked, found, or given away. They are subject to automated attacks including brute force attacks, in which possible passwords are tried until the password is found, or dictionary attacks, where words and word combinations are tested as possible passwords. But if a password or PIN must be supplied along with a one-time password supplied by a token, a fingerprint, or some other factor, the password is of no value unless the other factor(s) used for authentication are acquired along with it.

Encryption is used to protect the data that is sent between the remote computer and the Intermediate System. Data encryption is important for anyone who wants or needs secure data transfer. Encryption is needed when there is a risk of unauthorized interception of transmissions on the communications link. This is especially important when using the Internet as the communication means.

**Summary of Changes:** This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

**Reference to prior version:** (Part 2.1) New

**Change Rationale:** (Part 2.1)

*This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.*

**Reference to prior version:** (Part 2.2) CIP-007-5(X), R3.1

**Change Rationale:** (Part 2.2)

*This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The purpose of this part is to protect the confidentiality and integrity of each Interactive Remote Access session.*

**Reference to prior version:** (Part 2.3) CIP-007-5(X), R3.2

**Change Rationale:** (Part 2.3)

*This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The multi-factor authentication methods are also the same as those identified in the Homeland Security Presidential Directive 12 (HSPD-12), issued August 12, 2007.*

## Version History

| Version     | Date       | Action  | Change Tracking   |
|-------------|------------|---|---|
| 1           | 1/16/06    | R3.2 — Change “Control Center” to “control center.”   | 3/24/06   |
| 2           | 9/30/09    | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3           | 12/16/09   | Updated version number from -2 to -3<br>Approved by the NERC Board of Trustees.   |   |
| 3           | 3/31/10    | Approved by FERC.   |   |
| 4           | 12/30/10   | Modified to add specific criteria for Critical Asset identification.  | Update  |
| 4           | 1/24/11    | Approved by the NERC Board of Trustees.   | Update  |
| 5           | 11/26/12   | Adopted by the NERC Board of Trustees.  | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |
| 5           | 11/22/13   | FERC Order issued approving CIP-005-5. (Order becomes effective on 2/3/14.)   |   |
| <u>5(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial</u>             |

|  |  |  |                                  |
|--|--|--|----------------------------------|
|  |  |  | <u>Action Scheme<br/>and RAS</u> |
|--|--|--|----------------------------------|



## A. Introduction

1. **Title:** Cyber Security — Physical Security of BES Cyber Systems
2. **Number:** CIP-006-5(X)
3. **Purpose:** To manage physical access to BES Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**

#### **4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-006-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-006-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-006-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-006-5 exists as part of a suite of CIP Standards related to cyber security. CIP-002-5(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies,

assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **"Applicable Systems" Columns in Tables:**

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact

and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems without External Routable Connectivity** – Only applies to medium impact BES Cyber Systems without External Routable Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Locally mounted hardware or devices at the Physical Security Perimeter** – Applies to the locally mounted hardware or devices (e.g. such as motion sensors, electronic lock control mechanisms, and badge readers) at a Physical Security Perimeter associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity, and that does not contain or store access control information or independently perform access authentication. These hardware and devices are excluded in the definition of Physical Access Control Systems.



**B. Requirements and Measures**

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning and Same Day Operations].
- M1.** Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

| CIP-006-5(X) Table R1 – Physical Security Plan |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 1.1  | Medium Impact BES Cyber Systems without External Routable Connectivity<br><br>Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> | Define operational or procedural controls to restrict physical access. | An example of evidence may include, but is not limited to, documentation that operational or procedural controls exist. |

| CIP-006-5(X) Table R1 – Physical Security Plan |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 1.2  | <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Utilize at least one physical access control to allow unescorted physical access into each applicable Physical Security Perimeter to only those individuals who have authorized unescorted physical access.</p> | <p>An example of evidence may include, but is not limited to, language in the physical security plan that describes each Physical Security Perimeter and how unescorted physical access is controlled by one or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.</p> |



| CIP-006-5(X) Table R1 – Physical Security Plan |   |  |  |
|--|---|--|--|
| Part   | Applicable Systems  | Requirements   | Measures   |
| 1.3  | High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | Where technically feasible, utilize two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into Physical Security Perimeters to only those individuals who have authorized unescorted physical access. | An example of evidence may include, but is not limited to, language in the physical security plan that describes the Physical Security Perimeters and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs. |

| CIP-006-5(X) Table R1– Physical Security Plan |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 1.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p> | <p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p> |

| CIP-006-5(X) Table R1– Physical Security Plan |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 1.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Issue an alarm or alert in response to detected unauthorized access through a physical access point into a Physical Security Perimeter to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection.</p> | <p>An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a Physical Security Perimeter and additional evidence that the alarm or alert was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.</p> |
| 1.6   | <p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul>   | <p>Monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control System.</p>   | <p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a PACS.</p>   |

| CIP-006-5(X) Table R1– Physical Security Plan |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 1.7   | Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> | Issue an alarm or alert in response to detected unauthorized physical access to a Physical Access Control System to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of the detection. | An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to Physical Access Control Systems and additional evidence that the alarm or alerts was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated. |

| CIP-006-5(X) Table R1 – Physical Security Plan |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirements  | Measures   |
| 1.8  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access into each Physical Security Perimeter, with information to identify the individual and date and time of entry.</p> | <p>An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of physical entry into each Physical Security Perimeter and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into Physical Security Perimeters that show the individual and the date and time of entry into Physical Security Perimeter.</p> |

| CIP-006-5(X) Table R1 – Physical Security Plan |   |  |  |
|--|---|--|--|
| Part   | Applicable Systems  | Requirements   | Measures   |
| 1.9  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Retain physical access logs of entry of individuals with authorized unescorted physical access into each Physical Security Perimeter for at least ninety calendar days.</p> | <p>An example of evidence may include, but is not limited to, dated documentation such as logs of physical access into Physical Security Perimeters that show the date and time of entry into Physical Security Perimeter.</p> |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented visitor control programs that include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations.]
- M2.** Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-006-5(X) Table R2 – Visitor Control Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each Physical Security Perimeter, except during CIP Exceptional Circumstances.</p> | <p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as visitor logs.</p> |

| CIP-006-5(X) Table R2 – Visitor Control Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Require manual or automated logging of visitor entry into and exit from the Physical Security Perimeter that includes date and time of the initial entry and last exit, the visitor’s name, and the name of an individual point of contact responsible for the visitor, except during CIP Exceptional Circumstances.</p> | <p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as dated visitor logs that include the required information.</p> |
| 2.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Retain visitor logs for at least ninety calendar days.</p>   | <p>An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety calendar days.</p>  |

- R3.** Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program*. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].
- M3.** Evidence must include each of the documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-006-5(X) Table R3 – Physical Access Control System Maintenance and Testing Program |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirement   | Measures   |
| 3.1  | <p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> <p>Locally mounted hardware or devices at the Physical Security Perimeter associated with:</p> <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> | <p>Maintenance and testing of each Physical Access Control System and locally mounted hardware or devices at the Physical Security Perimeter at least once every 24 calendar months to ensure they function properly.</p> | <p>An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each Physical Access Control System and locally mounted hardware or devices associated with each applicable Physical Security Perimeter at least once every 24 calendar months and additional evidence to demonstrate that this testing was done, such as dated maintenance records, or other documentation showing testing and maintenance has been performed on each applicable device or system at least once every 24 calendar months.</p> |



## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon                              | VRF    | Violation Severity Levels (CIP-006-5(X))  |   |  |  |
|-----|---|--------|---|---|--|--|
|     |   |        | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
| R1  | Long Term Planning<br>Same-Day Operations | Medium | <p>The Responsible Entity has a process to log authorized physical entry into any Physical Security Perimeter with sufficient information to identify the individual and date and time of entry and identified deficiencies but did not assess or correct the deficiencies. (1.8)</p> <p>OR</p> <p>The Responsible Entity has a process to log authorized physical entry into any Physical Security</p> | <p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has</p> | <p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter and identified deficiencies but did not assess or correct the deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter but did not identify, assess, or correct deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct</p> | <p>The Responsible Entity did not document or implement operational or procedural controls to restrict physical access. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access and identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access but did not identify, assess, or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X))   |   |   |  |
|-----|--------------|-----|--|---|---|--|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | Perimeter with sufficient information to identify the individual and date and time of entry but did not identify, assess, or correct the deficiencies. (1.8)<br>OR<br>The Responsible Entity has a process to retain physical access logs for 90 calendar days and identified deficiencies but did not assess or correct the deficiencies. (1.9)<br>OR<br>The Responsible Entity has a process to retain physical access logs for 90 | a process communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.7) | the deficiencies. (1.5)<br>OR<br>The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.5)<br>OR<br>The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.6)<br>OR<br>The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.6) | documented and implemented physical access controls, but at least one control does not exist to restrict access to Applicable Systems. (1.2)<br>OR<br>The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, and identified deficiencies, but did not assess or correct the deficiencies. (1.2)<br>OR<br>The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, but did not identify, assess, or correct the deficiencies. (1.2)<br>OR<br>The Responsible Entity has |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X))                                       |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL  |
|     |              |     | calendar days but did not identify, assess, or correct the deficiencies. (1.9) |              |          | documented and implemented physical access controls, but at least two different controls do not exist to restrict access to Applicable Systems. (1.3)<br>OR<br>The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, and identified deficiencies, but did not assess or correct the deficiencies. (1.3)<br>OR<br>The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, but did not identify, assess, or correct |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | the deficiencies. (1.3)<br>OR<br>The Responsible Entity does not have a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter. (1.4)<br>OR<br>The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter and identified deficiencies, but did not assess or correct the deficiencies. (1.4)<br>OR<br>The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter, but did not identify, assess, or correct the deficiencies. |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | (1.4)<br>OR<br>The Responsible Entity does not have a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter or to communicate such alerts within 15 minutes to identified personnel. (1.5)<br>OR<br>The Responsible Entity does not have a process to monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control Systems. (1.6)<br>OR<br>The Responsible Entity does not have a process to alert for unauthorized physical access to Physical Access Control Systems or to communicate such alerts within 15 minutes to |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-006-5(X)) |   |  |   |
|-----------|----------------------------|---------------|--|---|--|---|
|           |                            |               | Lower VSL                                | Moderate VSL  | High VSL   | Severe VSL  |
|           |                            |               |  |   |  | identified personnel (1.7)<br>OR<br>The Responsible Entity does not have a process to log authorized physical entry into each Physical Security Perimeter with sufficient information to identify the individual and date and time of entry. (1.8)<br>OR<br>The Responsible Entity does not have a process to retain physical access logs for 90 calendar days. (1.9) |
| <b>R2</b> | <b>Same-Day Operations</b> | <b>Medium</b> | N/A                                      | The Responsible Entity included a visitor control program that requires logging of each of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact and identified deficiencies but did not assess or correct the deficiencies. (2.2) | The Responsible Entity included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter, and identified deficiencies but did not assess or correct deficiencies. (2.1)<br>OR<br>The Responsible Entity | The Responsible Entity has failed to include or implement a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter. (2.1)<br>OR<br>The Responsible Entity has failed to include or implement a visitor   |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X)) |  |  |   |
|-----|--------------|-----|--|--|--|---|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL  |
|     |              |     |  | <p>OR</p> <p>The Responsible Entity included a visitor control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact and but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days and identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days but did not identify, assess, or correct the deficiencies. (2.3)</p> | <p>included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter but did not identify, assess, or correct deficiencies. (2.1)</p> | <p>control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact. (2.2)</p> <p>OR</p> <p>The Responsible Entity failed to include or implement a visitor control program to retain visitor logs for at least ninety days. (2.3)</p> |



| R #       | Time Horizon              | VRF          | Violation Severity Levels (CIP-006-5(X))   |  |  |   |
|-----------|---------------------------|--------------|--|--|--|---|
|           |                           |              | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
| <b>R3</b> | <b>Long Term Planning</b> | <b>Lower</b> | The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 24 calendar months but did complete required testing within 25 calendar months. (3.1) | The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 25 calendar months but did complete required testing within 26 calendar months. (3.1) | The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 26 calendar months but did complete required testing within 27 calendar months. (3.1) | The Responsible Entity has not documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter. (3.1)<br><br>OR<br>The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 27 calendar months. (3.1) |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### **General:**

While the focus is shifted from the definition and management of a completely enclosed “six-wall” boundary, it is expected in many instances this will remain a primary mechanism for controlling, alerting, and logging access to BES Cyber Systems. Taken together, these controls will effectively constitute the physical security plan to manage physical access to BES Cyber Systems.

#### **Requirement R1:**

Methods of physical access control include:

- **Card Key:** A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- **Special Locks:** These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- **Security Personnel:** Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.

- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access into the Physical Security Perimeter.

Methods to monitor physical access include:

- Alarm Systems: Systems that alarm to indicate interior motion or when a door, gate, or window has been opened without authorization. These alarms must provide for notification within 15 minutes to individuals responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by security personnel who are also controlling physical access.

Methods to log physical access include:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and alerting method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access.

The FERC Order No. 706, Paragraph 572, directive discussed utilizing two or more different and complementary physical access controls to provide defense in depth. It does not require two or more Physical Security Perimeters, nor does it exclude the use of layered perimeters. Use of two-factor authentication would be acceptable at the same entry points for a non-layered single perimeter. For example, a sole perimeter's controls could include either a combination of card key and pin code (something you know and something you have), or a card key and biometric scanner (something you have and something you are), or a physical key in combination with a guard-monitored remote camera and door release, where the "guard" has adequate information to authenticate the person they are observing or talking to prior to permitting access (something you have and something you are). The two-factor authentication could be implemented using a single Physical Access Control System but more than one authentication method must be utilized. For physically layered protection, a locked gate in combination with a locked control-building could be acceptable, provided no single authenticator (e.g., key or card key) would provide access through both.

Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.

### **Requirement R2:**

The logging of visitors should capture each visit of the individual and does not need to capture each entry or exit during that visit. This is meant to allow a visitor to temporarily exit the Physical Security Perimeter to obtain something they left in their vehicle or outside the area without requiring a new log entry for each and every entry during the visit.

The SDT also determined that a point of contact should be documented who can provide additional details about the visit if questions arise in the future. The point of contact could be the escort, but there is no need to document everyone that acted as an escort for the visitor.

**Requirement R3:**

This includes the testing of locally mounted hardware or devices used in controlling, alerting or logging access to the Physical Security Perimeter. This includes motion sensors, electronic lock control mechanisms, and badge readers which are not deemed to be part of the Physical Access Control System but are required for the protection of the BES Cyber Systems.

**Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

**Rationale for R1:**

Each Responsible Entity shall ensure that physical access to all BES Cyber Systems is restricted and appropriately managed. *Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.*

**Summary of Changes:** The entire content of CIP-006-5(X) is intended to constitute a physical security program. This represents a change from previous versions, since there was no specific requirement to have a physical security program in previous versions of the standards, only requirements for physical security plans.

Added details to address FERC Order No. 706, Paragraph 572, directives for physical security defense in depth.

Additional guidance on physical security defense in depth provided to address the directive in FERC Order No. 706, Paragraph 575.

**Reference to prior version:** (Part 1.1) CIP-006-4c, R2.1 for Physical Access Control Systems  
*New Requirement for Medium Impact BES Cyber Systems not having External Routable Connectivity*

**Change Rationale:** (Part 1.1)

*To allow for programmatic protection controls as a baseline (which also includes how the entity plans to protect Medium Impact BES Cyber Systems that do not have External Routable Connectivity not otherwise covered under Part 1.2, and it does not require a detailed list of individuals with access). Physical Access Control Systems do not themselves need to be protected at the same level as required in Parts 1.2 through 1.5.*

**Reference to prior version:** (Part 1.2) CIP006-4c, R3 & R4

**Change Rationale:** (Part 1.2)

*This requirement has been made more general to allow for alternate measures of restricting physical access. Specific examples of methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.3) CIP006-4c, R3 & R4

**Change Rationale:** (Part 1.3)

*The specific examples that specify methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section. This requirement has been made more general to allow for alternate measures of controlling physical access.*

*Added to address FERC Order No. 706, Paragraph 572, related directives for physical security defense in depth.*

*FERC Order No. 706, Paragraph 575, directives addressed by providing the examples in the guidance document of physical security defense in depth via multi-factor authentication or layered Physical Security Perimeter(s).*

**Reference to prior version:** (Part 1.4) CIP006-4c, R5

**Change Rationale:** (Part 1.4)

*Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.5) CIP006-4c, R5

**Change Rationale:** (Part 1.5)

*Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.6) CIP006-4c, R5

**Change Rationale:** (Part 1.6)

*Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.*

**Reference to prior version:** (Part 1.7) CIP006-4c, R5

**Change Rationale:** (Part 1.7)

*Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.*

**Reference to prior version:** (Part 1.8) CIP-006-4c, R6

**Change Rationale:** (Part 1.8)

*CIP-006-4c, Requirement R6 was specific to the logging of access at identified access points. This requirement more generally requires logging of authorized physical access into the Physical Security Perimeter.*

*Examples of logging methods have been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.9) CIP-006-4c, R7

**Change Rationale:** (Part 1.9)

*No change.*

**Rationale for R2:**

To control when personnel without authorized unescorted physical access can be in any Physical Security Perimeters protecting BES Cyber Systems or Electronic Access Control or Monitoring Systems, as applicable in Table R2.

**Summary of Changes:** Reformatted into table structure. Originally added in Version 3 per FERC Order issued September 30, 2009.

**Reference to prior version:** (Part 2.1) CIP-006-4c, R1.6.2

**Change Rationale:** (Part 2.1)

*Added the ability to not do this during CIP Exceptional Circumstances.*

**Reference to prior version:** (Part 2.2) CIP-006-4c R1.6.1

**Change Rationale:** (Part 2.2)

*Added the ability to not do this during CIP Exceptional Circumstances, addressed multi-entry scenarios of the same person in a day (log first entry and last exit), and name of the person who is responsible or sponsor for the visitor. There is no requirement to document the escort or handoffs between escorts.*

**Reference to prior version:** (Part 2.3) CIP-006-4c, R7

**Change Rationale:** (Part 2.3)

*No change*

**Rationale for R3:**

To ensure all Physical Access Control Systems and devices continue to function properly.

**Summary of Changes:** Reformatted into table structure.

Added details to address FERC Order No. 706, Paragraph 581, directives to test more frequently than every three years.

**Reference to prior version:** (Part 3.1) CIP-006-4c, R8.1 and R8.2

**Change Rationale:** (Part 3.1)

*Added details to address FERC Order No. 706, Paragraph 581 directives to test more frequently than every three years. The SDT determined that annual testing was too often and agreed on two years.*

**Version History**

| Version | Date     | Action  | Change Tracking   |
|---------|----------|---|---|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”   | 3/24/06   |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br><br>Removal of reasonable business judgment.<br><br>Replaced the RRO with the RE as a responsible entity.<br><br>Rewording of Effective Date.<br><br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3       | 12/16/09 | Updated Version Number from -2 to -3<br><br>In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.  |   |
| 3       | 12/16/09 | Approved by the NERC Board of Trustees.   |   |
| 3       | 3/31/10  | Approved by FERC.   |   |
| 4       | 1/24/11  | Approved by the NERC Board of Trustees.   |   |
| 5       | 11/26/12 | Adopted by the NERC Board of Trustees.  | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |



## Guidelines and Technical Basis

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| Version | Date     | Action  | Change Tracking  |
|---------|----------|---|--|
| 5       | 11/22/13 | FERC Order issued approving CIP-006-5. (Order becomes effective on 2/3/14.) |  |
| 5(X)    | TBD      | Adopted by the NERC Board of Trustees                                       | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Cyber Security — Physical Security of BES Cyber Systems
2. **Number:** CIP-006-5(X)
3. **Purpose:** To manage physical access to BES Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**

#### 4.1.7 Transmission Operator

#### 4.1.8 Transmission Owner

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-006-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-006-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-006-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-006-5 exists as part of a suite of CIP Standards related to cyber security. CIP-002-5(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common BES controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept

from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems without External Routable Connectivity** – Only applies to medium impact BES Cyber Systems without External Routable Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Locally mounted hardware or devices at the Physical Security Perimeter** – Applies to the locally mounted hardware or devices (e.g. such as motion sensors, electronic lock control mechanisms, and badge readers) at a Physical Security Perimeter associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity, and that does not contain or store access control information or independently perform access authentication. These hardware and devices are excluded in the definition of Physical Access Control Systems.



**B. Requirements and Measures**

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning and Same Day Operations].
- M1.** Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

| CIP-006-5(X) Table R1 – Physical Security Plan |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 1.1  | Medium Impact BES Cyber Systems without External Routable Connectivity<br><br>Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> | Define operational or procedural controls to restrict physical access. | An example of evidence may include, but is not limited to, documentation that operational or procedural controls exist. |



| CIP-006-5(X) Table R1 – Physical Security Plan |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 1.2  | <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Utilize at least one physical access control to allow unescorted physical access into each applicable Physical Security Perimeter to only those individuals who have authorized unescorted physical access.</p> | <p>An example of evidence may include, but is not limited to, language in the physical security plan that describes each Physical Security Perimeter and how unescorted physical access is controlled by one or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.</p> |

| CIP-006-5(X) Table R1 – Physical Security Plan |   |  |  |
|--|---|--|--|
| Part   | Applicable Systems  | Requirements   | Measures   |
| 1.3  | High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | Where technically feasible, utilize two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into Physical Security Perimeters to only those individuals who have authorized unescorted physical access. | An example of evidence may include, but is not limited to, language in the physical security plan that describes the Physical Security Perimeters and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs. |

| CIP-006-5(X) Table R1– Physical Security Plan |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 1.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p> | <p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p> |

| CIP-006-5(X) Table R1– Physical Security Plan |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 1.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Issue an alarm or alert in response to detected unauthorized access through a physical access point into a Physical Security Perimeter to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection.</p> | <p>An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a Physical Security Perimeter and additional evidence that the alarm or alert was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.</p> |
| 1.6   | <p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul>   | <p>Monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control System.</p>   | <p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a PACS.</p>   |

| CIP-006-5(X) Table R1– Physical Security Plan |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 1.7   | Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> | Issue an alarm or alert in response to detected unauthorized physical access to a Physical Access Control System to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of the detection. | An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to Physical Access Control Systems and additional evidence that the alarm or alerts was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated. |

| CIP-006-5(X) Table R1 – Physical Security Plan |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirements  | Measures   |
| 1.8  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access into each Physical Security Perimeter, with information to identify the individual and date and time of entry.</p> | <p>An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of physical entry into each Physical Security Perimeter and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into Physical Security Perimeters that show the individual and the date and time of entry into Physical Security Perimeter.</p> |

| CIP-006-5(X) Table R1 – Physical Security Plan |   |  |  |
|--|---|--|--|
| Part   | Applicable Systems  | Requirements   | Measures   |
| 1.9  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Retain physical access logs of entry of individuals with authorized unescorted physical access into each Physical Security Perimeter for at least ninety calendar days.</p> | <p>An example of evidence may include, but is not limited to, dated documentation such as logs of physical access into Physical Security Perimeters that show the date and time of entry into Physical Security Perimeter.</p> |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented visitor control programs that include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations.]
- M2.** Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-006-5(X) Table R2 – Visitor Control Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each Physical Security Perimeter, except during CIP Exceptional Circumstances.</p> | <p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as visitor logs.</p> |

| CIP-006-5(X) Table R2 – Visitor Control Program |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 2.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Require manual or automated logging of visitor entry into and exit from the Physical Security Perimeter that includes date and time of the initial entry and last exit, the visitor’s name, and the name of an individual point of contact responsible for the visitor, except during CIP Exceptional Circumstances.</p> | <p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as dated visitor logs that include the required information.</p> |
| 2.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | <p>Retain visitor logs for at least ninety calendar days.</p>   | <p>An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety calendar days.</p>  |



- R3.** Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program*. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].
- M3.** Evidence must include each of the documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-006-5(X) Table R3 – Physical Access Control System Maintenance and Testing Program |   |  |   |
|--|---|--|---|
| Part   | Applicable Systems  | Requirement  | Measures  |
| 3.1  | Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> Locally mounted hardware or devices at the Physical Security Perimeter associated with: <ul style="list-style-type: none"> <li>• High Impact BES Cyber Systems, or</li> <li>• Medium Impact BES Cyber Systems with External Routable Connectivity</li> </ul> | Maintenance and testing of each Physical Access Control System and locally mounted hardware or devices at the Physical Security Perimeter at least once every 24 calendar months to ensure they function properly. | An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each Physical Access Control System and locally mounted hardware or devices associated with each applicable Physical Security Perimeter at least once every 24 calendar months and additional evidence to demonstrate that this testing was done, such as dated maintenance records, or other documentation showing testing and maintenance has been performed on each applicable device or system at least once every 24 calendar months. |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon                              | VRF    | Violation Severity Levels (CIP-006-5(X))  |   |  |  |
|-----|---|--------|---|---|--|--|
|     |   |        | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
| R1  | Long Term Planning<br>Same-Day Operations | Medium | <p>The Responsible Entity has a process to log authorized physical entry into any Physical Security Perimeter with sufficient information to identify the individual and date and time of entry and identified deficiencies but did not assess or correct the deficiencies. (1.8)</p> <p>OR</p> <p>The Responsible Entity has a process to log authorized physical entry into any Physical Security</p> | <p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has</p> | <p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter and identified deficiencies but did not assess or correct the deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter but did not identify, assess, or correct deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct</p> | <p>The Responsible Entity did not document or implement operational or procedural controls to restrict physical access. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access and identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access but did not identify, assess, or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X))   |   |   |  |
|-----|--------------|-----|--|---|---|--|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | Perimeter with sufficient information to identify the individual and date and time of entry but did not identify, assess, or correct the deficiencies. (1.8)<br>OR<br>The Responsible Entity has a process to retain physical access logs for 90 calendar days and identified deficiencies but did not assess or correct the deficiencies. (1.9)<br>OR<br>The Responsible Entity has a process to retain physical access logs for 90 | a process communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.7) | the deficiencies. (1.5)<br>OR<br>The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.5)<br>OR<br>The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.6)<br>OR<br>The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.6) | documented and implemented physical access controls, but at least one control does not exist to restrict access to Applicable Systems. (1.2)<br>OR<br>The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, and identified deficiencies, but did not assess or correct the deficiencies. (1.2)<br>OR<br>The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, but did not identify, assess, or correct the deficiencies. (1.2)<br>OR<br>The Responsible Entity has |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X))                                       |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL  | Moderate VSL | High VSL | Severe VSL  |
|     |              |     | calendar days but did not identify, assess, or correct the deficiencies. (1.9) |              |          | documented and implemented physical access controls, but at least two different controls do not exist to restrict access to Applicable Systems. (1.3)<br>OR<br>The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, and identified deficiencies, but did not assess or correct the deficiencies. (1.3)<br>OR<br>The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, but did not identify, assess, or correct |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     |  |              |          | <p>the deficiencies. (1.3)</p> <p>OR</p> <p>The Responsible Entity does not have a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter. (1.4)</p> <p>OR</p> <p>The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter and identified deficiencies, but did not assess or correct the deficiencies. (1.4)</p> <p>OR</p> <p>The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter, but did not identify, assess, or correct the deficiencies.</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | (1.4)<br>OR<br>The Responsible Entity does not have a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter or to communicate such alerts within 15 minutes to identified personnel. (1.5)<br>OR<br>The Responsible Entity does not have a process to monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control Systems. (1.6)<br>OR<br>The Responsible Entity does not have a process to alert for unauthorized physical access to Physical Access Control Systems or to communicate such alerts within 15 minutes to |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-006-5(X)) |   |  |   |
|-----------|----------------------------|---------------|--|---|--|---|
|           |                            |               | Lower VSL                                | Moderate VSL  | High VSL   | Severe VSL  |
|           |                            |               |  |   |  | identified personnel (1.7)<br>OR<br>The Responsible Entity does not have a process to log authorized physical entry into each Physical Security Perimeter with sufficient information to identify the individual and date and time of entry. (1.8)<br>OR<br>The Responsible Entity does not have a process to retain physical access logs for 90 calendar days. (1.9) |
| <b>R2</b> | <b>Same-Day Operations</b> | <b>Medium</b> | N/A                                      | The Responsible Entity included a visitor control program that requires logging of each of the initial entry and last exit dates and times of the visitor, the visitor's name, and the point of contact and identified deficiencies but did not assess or correct the deficiencies. (2.2) | The Responsible Entity included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter, and identified deficiencies but did not assess or correct deficiencies. (2.1)<br>OR<br>The Responsible Entity | The Responsible Entity has failed to include or implement a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter. (2.1)<br>OR<br>The Responsible Entity has failed to include or implement a visitor   |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-006-5(X)) |  |  |   |
|-----|--------------|-----|--|--|--|---|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL  |
|     |              |     |  | <p>OR</p> <p>The Responsible Entity included a visitor control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact and but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days and identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days but did not identify, assess, or correct the deficiencies. (2.3)</p> | <p>included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter but did not identify, assess, or correct deficiencies. (2.1)</p> | <p>control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact. (2.2)</p> <p>OR</p> <p>The Responsible Entity failed to include or implement a visitor control program to retain visitor logs for at least ninety days. (2.3)</p> |

| R # | Time Horizon       | VRF   | Violation Severity Levels (CIP-006-5(X))   |  |  |   |
|-----|--------------------|-------|--|--|--|---|
|     |                    |       | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
| R3  | Long Term Planning | Lower | The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 24 calendar months but did complete required testing within 25 calendar months. (3.1) | The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 25 calendar months but did complete required testing within 26 calendar months. (3.1) | The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 26 calendar months but did complete required testing within 27 calendar months. (3.1) | The Responsible Entity has not documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter. (3.1)<br>OR<br>The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 27 calendar months. (3.1) |



**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### **General:**

While the focus is shifted from the definition and management of a completely enclosed “six-wall” boundary, it is expected in many instances this will remain a primary mechanism for controlling, alerting, and logging access to BES Cyber Systems. Taken together, these controls will effectively constitute the physical security plan to manage physical access to BES Cyber Systems.

#### **Requirement R1:**

Methods of physical access control include:

- **Card Key:** A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- **Special Locks:** These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- **Security Personnel:** Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.

- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access into the Physical Security Perimeter.

Methods to monitor physical access include:

- Alarm Systems: Systems that alarm to indicate interior motion or when a door, gate, or window has been opened without authorization. These alarms must provide for notification within 15 minutes to individuals responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by security personnel who are also controlling physical access.

Methods to log physical access include:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and alerting method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access.

The FERC Order No. 706, Paragraph 572, directive discussed utilizing two or more different and complementary physical access controls to provide defense in depth. It does not require two or more Physical Security Perimeters, nor does it exclude the use of layered perimeters. Use of two-factor authentication would be acceptable at the same entry points for a non-layered single perimeter. For example, a sole perimeter's controls could include either a combination of card key and pin code (something you know and something you have), or a card key and biometric scanner (something you have and something you are), or a physical key in combination with a guard-monitored remote camera and door release, where the "guard" has adequate information to authenticate the person they are observing or talking to prior to permitting access (something you have and something you are). The two-factor authentication could be implemented using a single Physical Access Control System but more than one authentication method must be utilized. For physically layered protection, a locked gate in combination with a locked control-building could be acceptable, provided no single authenticator (e.g., key or card key) would provide access through both.

Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.

### **Requirement R2:**

The logging of visitors should capture each visit of the individual and does not need to capture each entry or exit during that visit. This is meant to allow a visitor to temporarily exit the Physical Security Perimeter to obtain something they left in their vehicle or outside the area without requiring a new log entry for each and every entry during the visit.

The SDT also determined that a point of contact should be documented who can provide additional details about the visit if questions arise in the future. The point of contact could be the escort, but there is no need to document everyone that acted as an escort for the visitor.

**Requirement R3:**

This includes the testing of locally mounted hardware or devices used in controlling, alerting or logging access to the Physical Security Perimeter. This includes motion sensors, electronic lock control mechanisms, and badge readers which are not deemed to be part of the Physical Access Control System but are required for the protection of the BES Cyber Systems.

**Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

**Rationale for R1:**

Each Responsible Entity shall ensure that physical access to all BES Cyber Systems is restricted and appropriately managed. *Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.*

**Summary of Changes:** The entire content of CIP-006-5(X) is intended to constitute a physical security program. This represents a change from previous versions, since there was no specific requirement to have a physical security program in previous versions of the standards, only requirements for physical security plans.

Added details to address FERC Order No. 706, Paragraph 572, directives for physical security defense in depth.

Additional guidance on physical security defense in depth provided to address the directive in FERC Order No. 706, Paragraph 575.

**Reference to prior version:** (Part 1.1) CIP-006-4c, R2.1 for Physical Access Control Systems  
*New Requirement for Medium Impact BES Cyber Systems not having External Routable Connectivity*

**Change Rationale:** (Part 1.1)

*To allow for programmatic protection controls as a baseline (which also includes how the entity plans to protect Medium Impact BES Cyber Systems that do not have External Routable Connectivity not otherwise covered under Part 1.2, and it does not require a detailed list of individuals with access). Physical Access Control Systems do not themselves need to be protected at the same level as required in Parts 1.2 through 1.5.*

**Reference to prior version:** (Part 1.2) CIP006-4c, R3 & R4

**Change Rationale:** (Part 1.2)

*This requirement has been made more general to allow for alternate measures of restricting physical access. Specific examples of methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.3) CIP006-4c, R3 & R4

**Change Rationale:** (Part 1.3)

*The specific examples that specify methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section. This requirement has been made more general to allow for alternate measures of controlling physical access.*

*Added to address FERC Order No. 706, Paragraph 572, related directives for physical security defense in depth.*

*FERC Order No. 706, Paragraph 575, directives addressed by providing the examples in the guidance document of physical security defense in depth via multi-factor authentication or layered Physical Security Perimeter(s).*

**Reference to prior version:** (Part 1.4) CIP006-4c, R5

**Change Rationale:** (Part 1.4)

*Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.5) CIP006-4c, R5

**Change Rationale:** (Part 1.5)

*Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.6) CIP006-4c, R5

**Change Rationale:** (Part 1.6)

*Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.*

**Reference to prior version:** (Part 1.7) CIP006-4c, R5

**Change Rationale:** (Part 1.7)

*Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.*

**Reference to prior version:** (Part 1.8) CIP-006-4c, R6

**Change Rationale:** (Part 1.8)



*CIP-006-4c, Requirement R6 was specific to the logging of access at identified access points. This requirement more generally requires logging of authorized physical access into the Physical Security Perimeter.*

*Examples of logging methods have been moved to the Guidelines and Technical Basis section.*

**Reference to prior version:** (Part 1.9) CIP-006-4c, R7

**Change Rationale:** (Part 1.9)

*No change.*

**Rationale for R2:**

To control when personnel without authorized unescorted physical access can be in any Physical Security Perimeters protecting BES Cyber Systems or Electronic Access Control or Monitoring Systems, as applicable in Table R2.

**Summary of Changes:** Reformatted into table structure. Originally added in Version 3 per FERC Order issued September 30, 2009.

**Reference to prior version:** (Part 2.1) CIP-006-4c, R1.6.2

**Change Rationale:** (Part 2.1)

*Added the ability to not do this during CIP Exceptional Circumstances.*

**Reference to prior version:** (Part 2.2) CIP-006-4c R1.6.1

**Change Rationale:** (Part 2.2)

*Added the ability to not do this during CIP Exceptional Circumstances, addressed multi-entry scenarios of the same person in a day (log first entry and last exit), and name of the person who is responsible or sponsor for the visitor. There is no requirement to document the escort or handoffs between escorts.*

**Reference to prior version:** (Part 2.3) CIP-006-4c, R7

**Change Rationale:** (Part 2.3)

*No change*

**Rationale for R3:**

To ensure all Physical Access Control Systems and devices continue to function properly.

**Summary of Changes:** Reformatted into table structure.

Added details to address FERC Order No. 706, Paragraph 581, directives to test more frequently than every three years.

**Reference to prior version:** (Part 3.1) CIP-006-4c, R8.1 and R8.2

**Change Rationale:** (Part 3.1)

*Added details to address FERC Order No. 706, Paragraph 581 directives to test more frequently than every three years. The SDT determined that annual testing was too often and agreed on two years.*

**Version History**

| Version | Date     | Action  | Change Tracking   |
|---------|----------|---|---|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”   | 3/24/06   |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br><br>Removal of reasonable business judgment.<br><br>Replaced the RRO with the RE as a responsible entity.<br><br>Rewording of Effective Date.<br><br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3       | 12/16/09 | Updated Version Number from -2 to -3<br><br>In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.  |   |
| 3       | 12/16/09 | Approved by the NERC Board of Trustees.   |   |
| 3       | 3/31/10  | Approved by FERC.   |   |
| 4       | 1/24/11  | Approved by the NERC Board of Trustees.   |   |
| 5       | 11/26/12 | Adopted by the NERC Board of Trustees.  | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |

## Guidelines and Technical Basis

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| Version     | Date       | Action  | Change Tracking   |
|-------------|------------|---|---|
| 5           | 11/22/13   | FERC Order issued approving CIP-006-5. (Order becomes effective on 2/3/14.) |   |
| <u>5(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>                                | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** Cyber Security — System Security Management
2. **Number:** CIP-007-5(X)
3. **Purpose:** To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**

#### **4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-007-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-007-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-007-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-007-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies**, . . .

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies,

assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **"Applicable Systems" Columns in Tables:**

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact

and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System in the applicability column. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.



## B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R1 – Ports and Services*. [*Violation Risk Factor: Medium*] [*Time Horizon: Same Day Operations.*]
- M1.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R1 – Ports and Services* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-007-5(X) Table R1– Ports and Services |   |   |  |
|---|---|---|--|
| Part                                      | Applicable Systems  | Requirements  | Measures   |
| 1.1                                       | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Documentation of the need for all enabled ports on all applicable Cyber Assets and Electronic Access Points, individually or by group.</li> <li>• Listings of the listening ports on the Cyber Assets, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or</li> <li>• Configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others.</li> </ul> |
| 1.2                                       | <p>High Impact BES Cyber Systems</p> <p>Medium Impact BES Cyber Systems at Control Centers</p>  | <p>Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or removable media.</p>  | <p>An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either logically through system configuration or physically using a port lock or signage.</p>  |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-007-5(X) Table R2 – Security Patch Management |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 2.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>A patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets. The tracking portion shall include the identification of a source or sources that the Responsible Entity tracks for the release of cyber security patches for applicable Cyber Assets that are updateable and for which a patching source exists.</p> | <p>An example of evidence may include, but is not limited to, documentation of a patch management process and documentation or lists of sources that are monitored, whether on an individual BES Cyber System or Cyber Asset basis.</p> |

| CIP-007-5(X) Table R2 – Security Patch Management |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 2.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>At least once every 35 calendar days, evaluate security patches for applicability that have been released since the last evaluation from the source or sources identified in Part 2.1.</p> | <p>An example of evidence may include, but is not limited to, an evaluation conducted by, referenced by, or on behalf of a Responsible Entity of security-related patches released by the documented sources at least once every 35 calendar days.</p> |

| CIP-007-5(X) Table R2 – Security Patch Management |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 2.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For applicable patches identified in Part 2.2, within 35 calendar days of the evaluation completion, take one of the following actions:</p> <ul style="list-style-type: none"> <li>• Apply the applicable patches; or</li> <li>• Create a dated mitigation plan; or</li> <li>• Revise an existing mitigation plan.</li> </ul> <p>Mitigation plans shall include the Responsible Entity’s planned actions to mitigate the vulnerabilities addressed by each security patch and a timeframe to complete these mitigations.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records of the installation of the patch (e.g., exports from automated patch management tools that provide installation date, verification of BES Cyber System Component software revision, or registry exports that show software has been installed); or</li> <li>• A dated plan showing when and how the vulnerability will be addressed, to include documentation of the actions to be taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch and a timeframe for the completion of these mitigations.</li> </ul> |

| CIP-007-5(X) Table R2 – Security Patch Management |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 2.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For each mitigation plan created or revised in Part 2.3, implement the plan within the timeframe specified in the plan, unless a revision to the plan or an extension to the timeframe specified in Part 2.3 is approved by the CIP Senior Manager or delegate.</p> | <p>An example of evidence may include, but is not limited to, records of implementation of mitigations.</p> |

- R3.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations].
- M3.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-007-5(X) Table R3 – Malicious Code Prevention |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 3.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Deploy method(s) to deter, detect, or prevent malicious code.</p> | <p>An example of evidence may include, but is not limited to, records of the Responsible Entity’s performance of these processes (e.g., through traditional antivirus, system hardening, policies, etc.).</p> |



| CIP-007-5(X) Table R3 – Malicious Code Prevention |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 3.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | Mitigate the threat of detected malicious code.  | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records of response processes for malicious code detection</li> <li>• Records of the performance of these processes when malicious code is detected.</li> </ul> |
| 3.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | For those methods identified in Part 3.1 that use signatures or patterns, have a process for the update of the signatures or patterns. The process must address testing and installing the signatures or patterns. | An example of evidence may include, but is not limited to, documentation showing the process used for the update of signatures or patterns.   |

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Assessment.]
- M4.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-007-5(X) Table R4 – Security Event Monitoring |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 4.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Log events at the BES Cyber System level (per BES Cyber System capability) or at the Cyber Asset level (per Cyber Asset capability) for identification of, and after-the-fact investigations of, Cyber Security Incidents that includes, as a minimum, each of the following types of events:</p> <ol style="list-style-type: none"> <li>4.1.1. Detected successful login attempts;</li> <li>4.1.2. Detected failed access attempts and failed login attempts;</li> <li>4.1.3. Detected malicious code.</li> </ol> | <p>Examples of evidence may include, but are not limited to, a paper or system generated listing of event types for which the BES Cyber System is capable of detecting and, for generated events, is configured to log. This listing must include the required types of events.</p> |

| CIP-007-5(X) Table R4 – Security Event Monitoring |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 4.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Generate alerts for security events that the Responsible Entity determines necessitates an alert, that includes, as a minimum, each of the following types of events (per Cyber Asset or BES Cyber System capability):</p> <ol style="list-style-type: none"> <li>4.2.1. Detected malicious code from Part 4.1; and</li> <li>4.2.2. Detected failure of Part 4.1 event logging.</li> </ol> | <p>Examples of evidence may include, but are not limited to, paper or system-generated listing of security events that the Responsible Entity determined necessitate alerts, including paper or system generated list showing how alerts are configured.</p> |

| CIP-007-5(X) Table R4 – Security Event Monitoring |  |   |  |
|---|--|---|--|
| Part  | Applicable Systems   | Requirements  | Measures   |
| 4.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, retain applicable event logs identified in Part 4.1 for at least the last 90 consecutive calendar days except under CIP Exceptional Circumstances.</p>             | <p>Examples of evidence may include, but are not limited to, documentation of the event log retention process and paper or system generated reports showing log retention configuration set at 90 days or greater.</p> |
| 4.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol>   | <p>Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 calendar days to identify undetected Cyber Security Incidents.</p> | <p>Examples of evidence may include, but are not limited to, documentation describing the review, any findings from the review (if any), and dated documentation showing the review occurred.</p>                      |

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R5 – System Access Controls*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M5.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table 5 – System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-007-5(X) Table R5 – System Access Control |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 5.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Have a method(s) to enforce authentication of interactive user access, where technically feasible.</p> | <p>An example of evidence may include, but is not limited to, documentation describing how access is authenticated.</p> |

| CIP-007-5(X) Table R5 – System Access Control |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 5.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Identify and inventory all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s).</p> | <p>An example of evidence may include, but is not limited to, a listing of accounts by account types showing the enabled or generic account types in use for the BES Cyber System.</p> |

| CIP-007-5(X) Table R5 – System Access Control |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 5.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | Identify individuals who have authorized access to shared accounts. | An example of evidence may include, but is not limited to, listing of shared accounts and the individuals who have authorized access to each shared account. |

| CIP-007-5(X) Table R5 – System Access Control |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 5.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | Change known default passwords, per Cyber Asset capability | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records of a procedure that passwords are changed when new devices are in production; or</li> <li>• Documentation in system manuals or other vendor documents showing default vendor passwords were generated pseudo-randomly and are thereby unique to the device.</li> </ul> |



| CIP-007-5(X) Table R5 – System Access Control |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 5.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For password-only authentication for interactive user access, either technically or procedurally enforce the following password parameters:</p> <ol style="list-style-type: none"> <li>5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the Cyber Asset; and</li> <li>5.5.2. Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the Cyber Asset.</li> </ol> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• System-generated reports or screen-shots of the system-enforced password parameters, including length and complexity; or</li> <li>• Attestations that include a reference to the documented procedures that were followed.</li> </ul> |

| CIP-007-5(X) Table R5 – System Access Control |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 5.6   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 calendar months.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• System-generated reports or screen-shots of the system-enforced periodicity of changing passwords; or</li> <li>• Attestations that include a reference to the documented procedures that were followed.</li> </ul> |

| CIP-007-5(X) Table R5 – System Access Control |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 5.7   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, either:</p> <ul style="list-style-type: none"> <li>• Limit the number of unsuccessful authentication attempts; or</li> <li>• Generate alerts after a threshold of unsuccessful authentication attempts.</li> </ul> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Documentation of the account-lockout parameters; or</li> <li>• Rules in the alerting configuration showing how the system notified individuals after a determined number of unsuccessful login attempts.</li> </ul> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

**2. Table of Compliance Elements**

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X)) |   |   |  |
|-----------|----------------------------|---------------|--|---|---|--|
|           |                            |               | Lower VSL                                | Moderate VSL  | High VSL  | Severe VSL   |
| <b>R1</b> | <b>Same Day Operations</b> | <b>Medium</b> | N/A                                      | <p>The Responsible Entity has implemented and documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media and has identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has implemented and</p> | <p>The Responsible Entity has implemented and documented processes for determining necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented and documented processes for determining</p> | <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R1 and has identified deficiencies but did not assess or correct the deficiencies. (R1)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R1 but did not</p> |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X))   |  |  |  |
|-----------|----------------------------|---------------|--|--|--|--|
|           |                            |               | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|           |                            |               |  | documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media but did not identify, assess, or correct the deficiencies. (1.2) | necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled but did not identify, assess, or correct the deficiencies. (1.1) | identify, assess, or correct the deficiencies. (R1)  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Medium</b> | The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the | The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of   | The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for                    | The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 and has identified deficiencies but did |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |  |   |   |
|-----|--------------|-----|---|--|---|---|
|     |              |     | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL  |
|     |              |     | security patches for applicability within 35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2)<br>OR<br>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within | sources, for tracking or evaluating cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)<br>OR<br>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of sources, for tracking, or evaluating cyber security patches for applicable Cyber Assets but did not | applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)<br>OR<br>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for applicable Cyber Assets but did not identify, assess, or correct the deficiencies. (2.1)<br>OR | not assess or correct the deficiencies. (R2)<br>OR<br>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 but did not identify, assess, or correct the deficiencies. (R2)<br>OR<br>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |  |  |
|-----|--------------|-----|---|---|--|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|     |              |     | <p>35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an</p> | <p>identify, assess, or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct</p> | <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or</p> | <p>tracking, evaluating, or installing cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for tracking, evaluating, or installing cyber security patches for applicable Cyber Assets but did not identify, assess, or</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a</p> | <p>the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> | <p>more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the days source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by</p> | <p>correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate and has identified deficiencies but did not assess or correct the deficiencies. (2.4)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | dated mitigation plan, or revise an existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3) | OR<br>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct | applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3)<br>OR<br>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by | an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate but did not identify, assess, or correct the deficiencies. (2.4)<br>OR<br>The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan and has identified deficiencies but did |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     |  | the deficiencies. (2.3)<br>OR<br>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion but did not identify, assess, | applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3) | not assess or correct the deficiencies. (2.4)<br>OR<br>The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan but did not identify, assess, or correct the deficiencies. (2.4) |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X)) |  |  |   |
|-----------|----------------------------|---------------|--|--|--|---|
|           |                            |               | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL  |
|           |                            |               |  | or correct the deficiencies. (2.3)   |  |   |
| <b>R3</b> | <b>Same Day Operations</b> | <b>Medium</b> |  | <p>The Responsible Entity has implemented one or more documented process(es), but, where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and has identified deficiencies but did not assess or correct the deficiencies. (3.3)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es), but,</p> | <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected</p> | <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R3 and has identified deficiencies but did not assess or correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     |  | <p>where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and did not identify, assess, or correct the deficiencies. (3.3)</p> | <p>malicious code and did not identify, assess, or correct the deficiencies. (3.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and has identified deficiencies but did not assess or correct the deficiencies. (3.3)</p> <p>OR</p> | <p>R3 and did not identify, assess, or correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or</p> |

| R #       | Time Horizon   | VRF           | Violation Severity Levels (CIP-007-5(X))  |   |   |   |
|-----------|--|---------------|---|---|---|---|
|           |  |               | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|           |  |               |   |   | The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and did not identify, assess, or correct the deficiencies. (3.3) | more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and did not identify, assess, or correct the deficiencies. (3.1) |
| <b>R4</b> | <b>Same Day Operations and Operations Assessment</b> | <b>Medium</b> | The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity- | The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity- | The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the  | The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and has  |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |   |  |
|-----|--------------|-----|---|---|---|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | <p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p> | <p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p> | <p>responsible entity) for the Applicable Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and has identified deficiencies but did not assess or correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the responsible entity) for the Applicable</p> | <p>identified deficiencies but did not assess or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and did not identify, assess, or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to log events for the</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))   |  |   |   |
|-----|--------------|-----|--|--|---|---|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|     |              |     | <p>summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4)</p> | <p>summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4)</p> | <p>Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and did not identify, assess, or correct the deficiencies. (4.2)<br/>OR<br/>The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event</p> | <p>Applicable Systems (per device or system capability) but did not detect and log all of the required types of events described in 4.1.1 through 4.1.3 and has identified deficiencies but did not assess or correct the deficiencies. (4.1)<br/>OR<br/>The Responsible Entity has documented and implemented one or more process(es) to log events for the Applicable Systems (per device or system capability) but did not detect and log all of the required types of</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |   |
|-----|--------------|-----|--|--------------|---|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
|     |              |     |  |              | <p>logs for at least the last 90 consecutive days and has identified deficiencies but did not assess or correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event logs for at least the last 90 consecutive days and did not</p> | <p>events described in 4.1.1 through 4.1.3 and did not identify, assess, or correct the deficiencies. (4.1)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |            |
|-----|--------------|-----|--|--------------|---|------------|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL |
|     |              |     |  |              | identify, assess, or correct the deficiencies. (4.3)<br><br>OR<br><br>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and has identified deficiencies but did not assess or correct the deficiencies. (4.4) |            |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X))  |   |  |  |
|-----------|----------------------------|---------------|---|---|--|--|
|           |                            |               | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|           |                            |               |   |   | OR<br>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and did not identify, assess, or correct the deficiencies. (4.4) |  |
| <b>R5</b> | <b>Operations Planning</b> | <b>Medium</b> | The Responsible Entity has implemented one or more documented process(es) for password-only | The Responsible Entity has implemented one or more documented process(es) for password-only | The Responsible Entity has implemented one or more documented process(es) for System Access  | The Responsible Entity did not implement or document one or more process(es) that included the |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))   |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p> | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p> | <p>Controls but, did not include the identification or inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and has identified deficiencies but did not assess or correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification or</p> | <p>applicable items in CIP-007-5(X) Table R5 and has identified deficiencies but did not assess or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R5 and did not identify, assess, or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))   |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)</p> | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)</p> | <p>inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and did not identify, assess, or correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and has identified</p> | <p>more documented process(es) for System Access Controls but, where technically feasible, does not have a method(s) to enforce authentication of interactive user access and has identified deficiencies but did not assess or correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, where technically feasible, does not have a</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | deficiencies but did not assess or correct the deficiencies. (5.3)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and did not identify, assess, or correct the deficiencies. (5.3)<br>OR<br>The Responsible Entity has implemented one or | method(s) to enforce authentication of interactive user access and did not identify, assess, or correct the deficiencies. (5.1)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords and has identified deficiencies but did not assess or correct the deficiencies. (5.4) |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | <p>more documented process(es) for password-only authentication for interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for</p> | <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords but did not identify, assess, or correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |  |  |
|-----|--------------|-----|--|--------------|--|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL   |
|     |              |     |  |              | <p>interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to</p> | <p>did not technically or procedurally enforce all of the password parameters described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity did not technically or procedurally enforce all of the</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to | password parameters described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and has |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |   |
|-----|--------------|-----|--|--------------|---|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
|     |              |     |  |              | change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6) | identified deficiencies but did not assess or correct the deficiencies. (5.6)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and did not identify, assess, or |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     |  |              |          | correct the deficiencies. (5.6)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and has identified deficiencies but did not assess or correct the deficiencies. (5.7) |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     |  |              |          | OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and did not identify, assess, or correct the deficiencies. (5.7) |

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

Requirement R1 exists to reduce the attack surface of Cyber Assets by requiring entities to disable known unnecessary ports. The SDT intends for the entity to know what network accessible (“listening”) ports and associated services are accessible on their assets and systems, whether they are needed for that Cyber Asset’s function, and disable or restrict access to all other ports.

**1.1.** This requirement is most often accomplished by disabling the corresponding service or program that is listening on the port or configuration settings within the Cyber Asset. It can also be accomplished through using host-based firewalls, TCP\_Wrappers, or other means on the Cyber Asset to restrict access. Note that the requirement is applicable at the Cyber Asset level. The Cyber Assets are those which comprise the applicable BES Cyber Systems and their associated Cyber Assets. This control is another layer in the defense against network-based attacks, therefore the SDT intends that the control be on the device itself, or positioned inline in a non-bypassable manner. Blocking ports at the ESP border does not substitute for this device level requirement. If a device has no provision for disabling or restricting logical ports on the device (example - purpose built devices that run from firmware with no port configuration available) then those ports that are open are deemed ‘needed.’

**1.2.** Examples of physical I/O ports include network, serial and USB ports external to the device casing. BES Cyber Systems should exist within a Physical Security Perimeter in which

case the physical I/O ports have protection from unauthorized access, but it may still be possible for accidental use such as connecting a modem, connecting a network cable that bridges networks, or inserting a USB drive. Ports used for 'console commands' primarily means serial ports on Cyber Assets that provide an administrative interface.

The protection of these ports can be accomplished in several ways including, but not limited to:

- Disabling all unneeded physical ports within the Cyber Asset's configuration
- Prominent signage, tamper tape, or other means of conveying that the ports should not be used without proper authorization
- Physical port obstruction through removable locks

This is a 'defense in depth' type control and it is acknowledged that there are other layers of control (the PSP for one) that prevent unauthorized personnel from gaining physical access to these ports. Even with physical access, it has been pointed out there are other ways to circumvent the control. This control, with its inclusion of means such as signage, is not meant to be a preventative control against intruders. Signage is indeed a directive control, not a preventative one. However, with a defense-in-depth posture, different layers and types of controls are required throughout the standard with this providing another layer for depth in Control Center environments. Once physical access has been achieved through the other preventative and detective measures by authorized personnel, a directive control that outlines proper behavior as a last line of defense are appropriate in these highest risk areas. In essence, signage would be used to remind authorized users to "think before you plug anything into one of these systems" which is the intent. This control is not designed primarily for intruders, but for example the authorized employee who intends to plug his possibly infected smartphone into an operator console USB port to charge the battery.

### **Requirement R2:**

The SDT's intent of Requirement R2 is to require entities to know, track, and mitigate the known software vulnerabilities associated with their BES Cyber Assets. It is not strictly an "install every security patch" requirement; the main intention is to "be aware of in a timely manner and manage all known vulnerabilities" requirement.

Patch management is required for BES Cyber Systems that are accessible remotely as well as standalone systems. Stand alone systems are vulnerable to intentional or unintentional introduction of malicious code. A sound defense-in-depth security strategy employs additional measures such as physical security, malware prevention software, and software patch management to reduce the introduction of malicious code or the exploit of known vulnerabilities.

One or multiple processes could be utilized. An overall assessment process may exist in a top tier document with lower tier documents establishing the more detailed process followed for individual systems. Lower tier documents could be used to cover BES Cyber System nuances that may occur at the system level.

**2.1.** The Responsible Entity is to have a patch management program that covers tracking, evaluating, and installing cyber security patches. The requirement applies to patches only,

which are fixes released to handle a specific vulnerability in a hardware or software product. The requirement covers only patches that involve cyber security fixes and does not cover patches that are purely functionality related with no cyber security impact. Tracking involves processes for notification of the availability of new cyber security patches for the Cyber Assets. Documenting the patch source in the tracking portion of the process is required to determine when the assessment timeframe clock starts. This requirement handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system. The source can take many forms. The National Vulnerability Database, Operating System vendors, or Control System vendors could all be sources to monitor for release of security related patches, hotfixes, and/or updates. A patch source is not required for Cyber Assets that have no updateable software or firmware (there is no user accessible way to update the internal software or firmware executing on the Cyber Asset), or those Cyber Assets that have no existing source of patches such as vendors that no longer exist. The identification of these sources is intended to be performed once unless software is changed or added to the Cyber Asset's baseline.

**2.2.** Responsible Entities are to perform an assessment of security related patches within 35 days of release from their monitored source. An assessment should consist of determination of the applicability of each patch to the entity's specific environment and systems. Applicability determination is based primarily on whether the patch applies to a specific software or hardware component that the entity does have installed in an applicable Cyber Asset. A patch that applies to a service or component that is not installed in the entity's environment is not applicable. If the patch is determined to be non-applicable, that is documented with the reasons why and the entity is compliant. If the patch is applicable, the assessment can include a determination of the risk involved, how the vulnerability can be remediated, the urgency and timeframe of the remediation, and the steps the entity has previously taken or will take. Considerable care must be taken in applying security related patches, hotfixes, and/or updates or applying compensating measures to BES Cyber System or BES Cyber Assets that are no longer supported by vendors. It is possible security patches, hotfixes, and updates may reduce the reliability of the system, and entities should take this into account when determining the type of mitigation to apply. The Responsible Entities can use the information provided in the Department of Homeland Security "Quarterly Report on Cyber Vulnerabilities of Potential Risk to Control Systems" as a source. The DHS document "Recommended Practice for Patch Management of Control Systems" provides guidance on an evaluative process. It uses severity levels determined using the Common Vulnerability Scoring System Version 2. Determination that a security related patch, hotfix, and/or update poses too great a risk to install on a system or is not applicable due to the system configuration should not require a TFE.

When documenting the remediation plan measures it may not be necessary to document them on a one to one basis. The remediation plan measures may be cumulative. A measure to address a software vulnerability may involve disabling a particular service. That same service may be exploited through other software vulnerabilities. Therefore disabling the single service has addressed multiple patched vulnerabilities.



**2.3.** The requirement handles the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity either installs the patch or documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. There are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability. For those security related patches that are determined to be applicable, the Responsible Entity must within 35 days either install the patch, create a dated mitigation plan which will outline the actions to be taken or those that have already been taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch, or revise an existing mitigation plan. Timeframes do not have to be designated as a particular calendar day but can have event designations such as “at next scheduled outage of at least two days duration.” “Mitigation plans” in the standard refers to internal documents and are not to be confused with plans that are submitted to Regional Entities in response to violations.

**2.4.** The entity has been notified of, has assessed, and has developed a plan to remediate the known risk and that plan must be implemented. Remediation plans that only include steps that have been previously taken are considered implemented upon completion of the documentation. Remediation plans that have steps to be taken to remediate the vulnerability must be implemented by the timeframe the entity documented in their plan. There is no maximum timeframe in this requirement as patching and other system changes carries its own risk to the availability and integrity of the systems and may require waiting until a planned outage. In periods of high demand or threatening weather, changes to systems may be curtailed or denied due to the risk to reliability.

**Requirement R3:**

**3.1.** Due to the wide range of equipment comprising the BES Cyber Systems and the wide variety of vulnerability and capability of that equipment to malware as well as the constantly evolving threat and resultant tools and controls, it is not practical within the standard to prescribe how malware is to be addressed on each Cyber Asset. Rather, the Responsible Entity determines on a BES Cyber System basis which Cyber Assets have susceptibility to malware intrusions and documents their plans and processes for addressing those risks and provides evidence that they follow those plans and processes. There are numerous options available including traditional antivirus solutions for common operating systems, white-listing solutions, network isolation techniques, portable storage media policies, Intrusion Detection/Prevention (IDS/IPS) solutions, etc. If an entity has numerous BES Cyber Systems or Cyber Assets that are of identical architecture, they may provide one process that describes how all the like Cyber Assets are covered. If a specific Cyber Asset has no updateable software and its executing code cannot be altered, then that Cyber Asset is considered to have its own internal method of deterring malicious code.

**3.2.** When malicious code is detected on a Cyber Asset within the applicability of this requirement, the threat posed by that code must be mitigated. In situations where traditional antivirus products are used, they may be configured to automatically remove or quarantine the malicious code. In white-listing situations, the white-listing tool itself can mitigate the threat as

it will not allow the code to execute, however steps should still be taken to remove the malicious code from the Cyber Asset. In some instances, it may be in the best interest of reliability to not immediately remove or quarantine the malicious code, such as when availability of the system may be jeopardized by removal while operating and a rebuild of the system needs to be scheduled. In that case, monitoring may be increased and steps taken to insure the malicious code cannot communicate with other systems. In some instances the entity may be working with law enforcement or other governmental entities to closely monitor the code and track the perpetrator(s). For these reasons, there is no maximum timeframe or method prescribed for the removal of the malicious code, but the requirement is to mitigate the threat posed by the now identified malicious code.

**3.3.** In instances where malware detection technologies depend on signatures or patterns of known attacks, the effectiveness of these tools against evolving threats is tied to the ability to keep these signatures and patterns updated in a timely manner. The entity is to have a documented process that includes the testing and installation of signature or pattern updates. In a BES Cyber System, there may be some Cyber Assets that would benefit from the more timely installation of the updates where availability of that Cyber Asset would not jeopardize the availability of the BES Cyber System's ability to perform its function. For example, some HMI workstations where portable media is utilized may benefit from having the very latest updates at all times with minimal testing. Other Cyber Assets should have any updates thoroughly tested before implementation where the result of a 'false positive' could harm the availability of the BES Cyber System. The testing should not negatively impact the reliability of the BES. The testing should be focused on the update itself and if it will have an adverse impact on the BES Cyber System. Testing in no way implies that the entity is testing to ensure that malware is indeed detected by introducing malware into the environment. It is strictly focused on ensuring that the update does not negatively impact the BES Cyber System before those updates are placed into production.

**Requirement R4:**

Refer to NIST 800-92 and 800-137 for additional guidance in security event monitoring.

**4.1.** In a complex computing environment and faced with dynamic threats and vulnerabilities, it is not practical within the standard to enumerate all security-related events necessary to support the activities for alerting and incident response. Rather, the Responsible Entity determines which computer generated events are necessary to log, provide alerts and monitor for their particular BES Cyber System environment.

Specific security events already required in Version 4 of the CIP Standards carry forward in this version. This includes access attempts at the Electronic Access Points, if any have been identified for a BES Cyber Systems. Examples of access attempts include: (i) blocked network access attempts, (ii) successful and unsuccessful remote user access attempts, (iii) blocked network access attempts from a remote VPN, and (iv) successful network access attempts or network flow information.

User access and activity events include those events generated by Cyber Assets within the Electronic Security Perimeter that have access control capability. These types of events include:

(i) successful and unsuccessful authentication, (ii) account management, (iii) object access, and (iv) processes started and stopped.

It is not the intent of the SDT that if a device cannot log a particular event that a TFE must be generated. The SDT's intent is that if any of the items in the bulleted list (for example, user logouts) can be logged by the device then the entity must log that item. If the device does not have the capability of logging that event, the entity remains compliant.

**4.2.** Real-time alerting allows the cyber system to automatically communicate events of significance to designated responders. This involves configuration of a communication mechanism and log analysis rules. Alerts can be configured in the form of an email, text message, or system display and alarming. The log analysis rules can exist as part of the operating system, specific application or a centralized security event monitoring system. On one end, a real-time alert could consist of a set point on an RTU for a login failure, and on the other end, a security event monitoring system could provide multiple alerting communications options triggered on any number of complex log correlation rules.

The events triggering a real-time alert may change from day to day as system administrators and incident responders better understand the types of events that might be indications of a cyber-security incident. Configuration of alerts also must balance the need for responders to know an event occurred with the potential inundation of insignificant alerts. The following list includes examples of events a Responsible Entity should consider in configuring real-time alerts:

- Detected known or potential malware or malicious activity
- Failure of security event logging mechanisms
- Login failures for critical accounts
- Interactive login of system accounts
- Enabling of accounts
- Newly provisioned accounts
- System administration or change tasks by an unauthorized user
- Authentication attempts on certain accounts during non-business hours
- Unauthorized configuration changes
- Insertion of removable media in violation of a policy

**4.3** Logs that are created under Part 4.1 are to be retained on the applicable Cyber Assets or BES Cyber Systems for at least 90 days. This is different than the evidence retention period called for in the CIP standards used to prove historical compliance. For such audit purposes, the entity should maintain evidence that shows that 90 days were kept historically. One example would be records of disposition of event logs beyond 90 days up to the evidence retention period.

**4.4.** Reviewing logs at least every 15 days (approximately every two weeks) can consist of analyzing a summarization or sampling of logged events. NIST SP800-92 provides a lot of guidance in periodic log analysis. If a centralized security event monitoring system is used, log analysis can be performed top-down starting with a review of trends from summary reports.

The log review can also be an extension of the exercise in identifying those events needing real-time alerts by analyzing events that are not fully understood or could possibly inundate the real-time alerting.

### **Requirement R5:**

Account types referenced in this guidance typically include:

- **Shared user account:** An account used by multiple users for normal business functions by employees or contractors. Usually on a device that does not support Individual User Accounts.
- **Individual user account:** An account used by a single user.
- **Administrative account:** An account with elevated privileges for performing administrative or other specialized functions. These can be individual or shared accounts.
- **System account:** Accounts used to run services on a system (web, DNS, mail etc). No users have access to these accounts.
- **Application account:** A specific system account, with rights granted at the application level often used for access into a Database.
- **Guest account:** An individual user account not typically used for normal business functions by employees or contractors and not associated with a specific user. May or may not be shared by multiple users.
- **Remote access account:** An individual user account only used for obtaining Interactive Remote Access to the BES Cyber System.
- **Generic account:** A group account set up by the operating system or application to perform specific operations. This differs from a shared user account in that individual users do not receive authorization for access to this account type.

**5.1** Reference the Requirement's rationale.

**5.2** Where possible, default and other generic accounts provided by a vendor should be removed, renamed, or disabled prior to production use of the Cyber Asset or BES Cyber System. If this is not possible, the passwords must be changed from the default provided by the vendor. Default and other generic accounts remaining enabled must be documented. For common configurations, this documentation can be performed at a BES Cyber System or more general level.

**5.3** Entities may choose to identify individuals with access to shared accounts through the access authorization and provisioning process, in which case the individual authorization records suffice to meet this Requirement Part. Alternatively, entities may choose to maintain a separate listing for shared accounts. Either form of evidence achieves the end result of maintaining control of shared accounts.

**5.4.** Default passwords can be commonly published in vendor documentation that is readily available to all customers using that type of equipment and possibly published online.

The requirement option to have unique password addresses cases where the Cyber Asset generates or has assigned pseudo-random default passwords at the time of production or installation. In these cases, the default password does not have to change because the system or manufacturer created it specific to the Cyber Asset.

**5.5.** Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Technical or procedural enforcement of password parameters are required where passwords are the only credential used to authenticate individuals. Technical enforcement of the password parameters means a Cyber Asset verifies an individually selected password meets the required parameters before allowing the account to authenticate with the selected password. Technical enforcement should be used in most cases when the authenticating Cyber Asset supports enforcing password parameters. Likewise, procedural enforcement means requiring the password parameters through procedures. Individuals choosing the passwords have the obligation of ensuring the password meets the required parameters.

Password complexity refers to the policy set by a Cyber Asset to require passwords to have one or more of the following types of characters: (1) lowercase alphabetic, (2) uppercase alphabetic, (3) numeric, and (4) non-alphanumeric or “special” characters (e.g. #, \$, @, &), in various combinations.

**5.6** Technical or procedural enforcement of password change obligations are required where passwords are the only credential used to authenticate individuals. Technical enforcement of password change obligations means the Cyber Asset requires a password change after a specified timeframe prior to allowing access. In this case, the password is not required to change by the specified time as long as the Cyber Asset enforces the password change after the next successful authentication of the account. Procedural enforcement means manually changing passwords used for interactive user access after a specified timeframe.

**5.7** Configuring an account lockout policy or alerting after a certain number of failed authentication attempts serves to prevent unauthorized access through an online password guessing attack. The threshold of failed authentication attempts should be set high enough to avoid false-positives from authorized users failing to authenticate. It should also be set low enough to account for online password attacks occurring over an extended period of time. This threshold may be tailored to the operating environment over time to avoid unnecessary account lockouts.

Entities should take caution when configuring account lockout to avoid locking out accounts necessary for the BES Cyber System to perform a BES reliability task. In such cases, entities should configure authentication failure alerting.

## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

The requirement is intended to minimize the attack surface of BES Cyber Systems through disabling or limiting access to unnecessary network accessible logical ports and services and physical I/O ports.

**Summary of Changes:** Changed the ‘needed for normal or emergency operations’ to those ports that are needed. Physical I/O ports were added in response to a FERC order. The unneeded physical ports in Control Centers (which are the highest risk, most impactful areas) should be protected as well.

**Reference to prior version:** (Part 1.1) CIP-007-4, R2.1 and R2.2

**Change Rationale:** (Part 1.1)

*The requirement focuses on the entity knowing and only allowing those ports that are necessary. The additional classification of ‘normal or emergency’ added no value and has been removed.*

**Reference to prior version:** (Part 1.2) New

**Change Rationale:** (Part 1.2)

*On March 18, 2010, FERC issued an order to approve NERC’s interpretation of Requirement R2 of CIP-007-2. In this order, FERC agreed the term “ports” in “ports and services” refers to logical communication (e.g. TCP/IP) ports, but they also encouraged the drafting team to address unused physical ports.*

### **Rationale for R2:**

Security patch management is a proactive way of monitoring and addressing known security vulnerabilities in software before those vulnerabilities can be exploited in a malicious manner to gain control of or render a BES Cyber Asset or BES Cyber System inoperable.

The remediation plan can be updated as necessary to maintain the reliability of the BES, including an explanation of any rescheduling of the remediation actions.

**Summary of Changes:** The existing wordings of CIP-007, Requirements R3, R3.1, and R3.2, were separated into individual line items to provide more granularity. The documentation of a source(s) to monitor for release of security related patches, hot fixes, and/or updates for BES Cyber System or BES Cyber Assets was added to provide context as to when the “release” date was. The current wording stated “document the assessment of security patches and security

upgrades for applicability within thirty calendar days of availability of the patches or upgrades” and there has been confusion as to what constitutes the availability date. Due to issues that may occur regarding Control System vendor license and service agreements, flexibility must be given to Responsible Entities to define what sources are being monitored for BES Cyber Assets.

**Reference to prior version:** (Part 2.1) CIP-007, R3

**Change Rationale:** (Part 2.1)

*The requirement is brought forward from previous CIP versions with the addition of defining the source(s) that a Responsible Entity monitors for the release of security related patches. Documenting the source is used to determine when the assessment timeframe clock starts. This requirement also handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system.*

**Reference to prior version:** (Part 2.2) CIP-007, R3.1

**Change Rationale:** (Part 2.2)

*Similar to the current wording but added “from the source or sources identified in 2.1” to clarify the 35-day time frame.*

**Reference to prior version:** (Part 2.3) CIP-007, R3.2

**Change Rationale:** (Part 2.3)

*The requirement has been changed to handle the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. The mitigation plan may, and in many cases will, consist of installing the patch. However, there are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability.*

**Reference to prior version:** (Part 2.4) CIP-007, R3.2

**Change Rationale:** (Part 2.4)

*Similar to the current wording but added that the plan must be implemented within the timeframe specified in the plan, or in a revised plan as approved by the CIP Senior Manager or delegate.*

**Rationale for R3:**

Malicious code prevention has the purpose of limiting and detecting the addition of malicious code onto the applicable Cyber Assets of a BES Cyber System. Malicious code (viruses, worms, botnets, targeted code such as Stuxnet, etc.) may compromise the availability or integrity of the BES Cyber System.

**Summary of Changes:** In prior versions, this requirement has arguably been the single greatest generator of TFEs as it prescribed a particular technology to be used on every CCA regardless of

that asset's susceptibility or capability to use that technology. As the scope of Cyber Assets in scope of these standards expands to more field assets, this issue will grow exponentially. The drafting team is taking the approach of making this requirement a competency based requirement where the entity must document how the malware risk is handled for each BES Cyber System, but it does not prescribe a particular technical method nor does it prescribe that it must be used on every Cyber Asset. The BES Cyber System is the object of protection.

Beginning in Paragraphs 619-622 of FERC Order No. 706, and in particular Paragraph 621, FERC agrees that the standard "does not need to prescribe a single method...However, how a responsible entity does this should be detailed in its cyber security policy so that it can be audited for compliance..."

In Paragraph 622, FERC directs that the requirement be modified to include safeguards against personnel introducing, either maliciously or unintentionally, viruses or malicious software through remote access, electronic media, or other means. The drafting team believes that addressing this issue holistically at the BES Cyber System level and regardless of technology, along with the enhanced change management requirements, meets this directive.

**Reference to prior version:** (Part 3.1) CIP-007-4, R4; CIP-007-4, R4.1

**Change Rationale:** (Part 3.1)

*See the Summary of Changes. FERC Order No. 706, Paragraph 621, states the standards development process should decide to what degree to protect BES Cyber Systems from personnel introducing malicious software.*

**Reference to prior version:** (Part 3.2) CIP-007-4, R4; CIP-007-4, R4.1

**Change Rationale:** (Part 3.2)

*See the Summary of Changes.*

**Reference to prior version:** (Part 3.3) CIP-007-4, R4; CIP-007-4, R4.2

**Change Rationale:** (Part 3.3)

*Requirement essentially unchanged from previous versions; updated to refer to previous parts of the requirement table.*

### **Rationale for R4:**

**Rationale for R4:** Security event monitoring has the purpose of detecting unauthorized access, reconnaissance and other malicious activity on BES Cyber Systems, and comprises of the activities involved with the collection, processing, alerting and retention of security-related computer logs. These logs can provide both (1) the detection of an incident and (2) useful evidence in the investigation of an incident. The retention of security-related logs is intended to support post-event data analysis.

Audit processing failures are not penalized in this requirement. Instead, the requirement specifies processes which must be in place to monitor for and notify personnel of audit processing failures.



**Summary of Changes:** Beginning in Paragraph 525 and also Paragraph 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis. This requirement combines CIP-005-4, R5 and CIP-007-4, R6 and addresses both directives from a system-wide perspective. The primary feedback received on this requirement from the informal comment period was the vagueness of terms “security event” and “monitor.”

The term “security event” or “events related to cyber security” is problematic because it does not apply consistently across all platforms and applications. To resolve this term, the requirement takes an approach similar to NIST 800-53 and requires the entity to define the security events relevant to the System. There are a few events explicitly listed that if a Cyber Asset or BES Cyber System can log, then it must log.

In addition, this requirement sets up parameters for the monitoring and reviewing of processes. It is rarely feasible or productive to look at every security log on the system. Paragraph 629 of the FERC Order No. 706 acknowledges this reality when directing a manual log review. As a result, this requirement allows the manual review to consist of a sampling or summarization of security events occurring since the last review.

**Reference to prior version:** (Part 4.1) CIP-005-4, R3; CIP-007-4, R5, R5.1.2, R6.1, and R6.3

**Change Rationale:** (Part 4.1)

*This requirement is derived from NIST 800-53 version 3 AU-2, which requires organizations to determine system events to audit for incident response purposes. The industry expressed confusion in the term “system events related to cyber security” from informal comments received on CIP-011. Access logs from the ESP as required in CIP-005-4 Requirement R3 and user access and activity logs as required in CIP-007-5 Requirement R5 are also included here.*

**Reference to prior version:** (Part 4.2) CIP-005-4, R3.2; CIP-007-4, R6.2

**Change Rationale:** (Part 4.2)

*This requirement is derived from alerting requirements in CIP-005-4, Requirement R3.2 and CIP-007-4, Requirement R6.2 in addition to NIST 800-53 version 3 AU-6. Previous CIP Standards required alerting on unauthorized access attempts and detected Cyber Security Incidents, which can be vast and difficult to determine from day to day. Changes to this requirement allow the entity to determine events that necessitate a response.*

**Reference to prior version:** (Part 4.3) CIP-005-4, R3.2; CIP-007-4, R6.4

**Change Rationale:** (Part 4.3)

*No substantive change.*

**Reference to prior version:** (Part 4.4) CIP-005-4, R3.2; CIP-007-4, R6.5

**Change Rationale:** (Part 4.4)

*Beginning in Paragraph 525 and also 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis and suggests a weekly review. The Order acknowledges it is rarely feasible to review all system logs. Indeed, log review is a dynamic process that should improve over time and with additional threat information.*

*Changes to this requirement allow for an approximately biweekly summary or sampling review of logs.*

**Rationale for R5:**

To help ensure that no authorized individual can gain electronic access to a BES Cyber System until the individual has been authenticated, i.e., until the individual's logon credentials have been validated. Requirement R5 also seeks to reduce the risk that static passwords, where used as authenticators, may be compromised.

Requirement Part 5.1 ensures the BES Cyber System or Cyber Asset authenticates individuals that can modify configuration information. This requirement addresses the configuration of authentication. The authorization of individuals is addressed elsewhere in the CIP Cyber Security Standards. Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Requirement Part 5.2 addresses default and other generic account types. Identifying the use of default or generic account types that could introduce vulnerabilities has the benefit ensuring entities understand the possible risk these accounts pose to the BES Cyber System. The Requirement Part avoids prescribing an action to address these accounts because the most effective solution is situation specific, and in some cases, removing or disabling the account could have reliability consequences.

Requirement Part 5.3 addresses identification of individuals with access to shared accounts. This Requirement Part has the objective of mitigating the risk of unauthorized access through shared accounts. This differs from other CIP Cyber Security Standards Requirements to authorize access. An entity can authorize access and still not know who has access to a shared account. Failure to identify individuals with access to shared accounts would make it difficult to revoke access when it is no longer needed. The term "authorized" is used in the requirement to make clear that individuals storing, losing, or inappropriately sharing a password is not a violation of this requirement.

Requirement 5.4 addresses default passwords. Changing default passwords closes an easily exploitable vulnerability in many systems and applications. Pseudo-randomly system generated passwords are not considered default passwords.

For password-based user authentication, using strong passwords and changing them periodically helps mitigate the risk of successful password cracking attacks and the risk of accidental password disclosure to unauthorized individuals. In these requirements, the drafting team considered multiple approaches to ensuring this requirement was both effective and flexible enough to allow Responsible Entities to make good security decisions. One of the approaches considered involved requiring minimum password entropy, but the calculation for

true information entropy is more highly complex and makes several assumptions in the passwords users choose. Users can pick poor passwords well below the calculated minimum entropy.

The drafting team also chose to not require technical feasibility exceptions for devices that cannot meet the length and complexity requirements in password parameters. The objective of this requirement is to apply a measurable password policy to deter password cracking attempts, and replacing devices to achieve a specified password policy does not meet this objective. At the same time, this requirement has been strengthened to require account lockout or alerting for failed login attempts, which in many instances better meets the requirement objective.

The requirement to change passwords exists to address password cracking attempts if an encrypted password were somehow attained and also to refresh passwords which may have been accidentally disclosed over time. The requirement permits the entity to specify the periodicity of change to accomplish this objective. Specifically, the drafting team felt determining the appropriate periodicity based on a number of factors is more effective than specifying the period for every BES Cyber System in the Standard. In general, passwords for user authentication should be changed at least annually. The periodicity may increase in some cases. For example, application passwords that are long and pseudo-randomly generated could have a very long periodicity. Also, passwords used only as a weak form of application authentication, such as accessing the configuration of a relay may only need to be changed as part of regularly scheduled maintenance.

The Cyber Asset should automatically enforce the password policy for individual user accounts. However, for shared accounts in which no mechanism exists to enforce password policies, the Responsible Entity can enforce the password policy procedurally and through internal assessment and audit.

Requirement Part 5.7 assists in preventing online password attacks by limiting the number of guesses an attacker can make. This requirement allows either limiting the number of failed authentication attempts or alerting after a defined number of failed authentication attempts. Entities should take caution in choosing to limit the number of failed authentication attempts for all accounts because this would allow the possibility for a denial of service attack on the BES Cyber System.

### **Summary of Changes (From R5):**

CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. For example, many have interpreted the password for tokens or biometrics must satisfy this policy and in some cases prevents the use of this stronger authentication. Also, longer passwords may preclude the use of strict complexity requirements. The password requirements have been changed to allow the entity to specify the most effective password parameters based on the impact of the BES Cyber System, the way passwords are used, and the significance of passwords in restricting access to the system. The SDT believes these changes strengthen the authentication

mechanism by requiring entities to look at the most effective use of passwords in their environment. Otherwise, prescribing a strict password policy has the potential to limit the effectiveness of security mechanisms and preclude better mechanisms in the future.

**Reference to prior version:** (Part 5.1) CIP-007-4, R5

**Change Rationale:** (Part 5.1)

*The requirement to enforce authentication for all user access is included here. The requirement to establish, implement, and document controls is included in this introductory requirement. The requirement to have technical and procedural controls was removed because technical controls suffice when procedural documentation is already required. The phrase “that minimize the risk of unauthorized access” was removed and more appropriately captured in the rationale statement.*

**Reference to prior version:** (Part 5.2) CIP-007-4, R5.2 and R5.2.1

**Change Rationale:** (Part 5.2)

*CIP-007-4 requires entities to minimize and manage the scope and acceptable use of account privileges. The requirement to minimize account privileges has been removed because the implementation of such a policy is difficult to measure at best.*

**Reference to prior version:** (Part 5.3) CIP-007-4, R5.2.2

**Change Rationale:** (Part 5.3)

*No significant changes. Added “authorized” access to make clear that individuals storing, losing or inappropriately sharing a password is not a violation of this requirement.*

**Reference to prior version:** (Part 5.4) CIP-007-4, R5.2.1

**Change Rationale:** (Part 5.4)

*The requirement for the “removal, disabling or renaming of such accounts where possible” has been removed and incorporated into guidance for acceptable use of account types. This was removed because those actions are not appropriate on all account types. Added the option of having unique default passwords to permit cases where a system may have generated a default password or a hard-coded uniquely generated default password was manufactured with the BES Cyber System.*

**Reference to prior version:** (Part 5.5) CIP-007-4, R5.3

**Change Rationale:** (Part 5.5)

*CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. The password requirements have been changed to permit the maximum allowed by the device in cases where the password parameters could otherwise not achieve a stricter policy. This change still achieves the requirement objective to minimize the risk of unauthorized disclosure of password*

*credentials while recognizing password parameters alone do not achieve this. The drafting team felt allowing the Responsible Entity the flexibility of applying the strictest password policy allowed by a device outweighed the need to track a relatively minimally effective control through the TFE process.*

**Reference to prior version:** (Part 5.6) CIP-007-4, R5.3.3

**Change Rationale:** (Part 5.6)

*\*This was originally Requirement R5.5.3, but moved to add “external routable connectivity” to medium impact in response to comments. This requirement is limited in scope because the risk to performing an online password attack is lessened by its lack of external routable connectivity. Frequently changing passwords at field assets can entail significant effort with minimal risk reduction.*

**Reference to prior version:** (Part 5.7) New Requirement

**Change Rationale:** (Part 5.7)

*Minimizing the number of unsuccessful login attempts significantly reduces the risk of live password cracking attempts. This is a more effective control in live password attacks than password parameters.*

### Version History

| Version | Date     | Action   | Change Tracking |
|---------|----------|--|-----------------|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”  | 3/24/06         |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |                 |
| 3       | 12/16/09 | Updated version number from -2 to -3<br>Approved by the NERC Board of Trustees.  |                 |

## Guidelines and Technical Basis

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|------|----------|---|--|
| 3    | 3/31/10  | Approved by FERC.   |  |
| 4    | 12/30/10 | Modified to add specific criteria for Critical Asset identification.        | Update   |
| 4    | 1/24/11  | Approved by the NERC Board of Trustees.                                     | Update   |
| 5    | 11/26/12 | Adopted by the NERC Board of Trustees.                                      | Modified to coordinate with other CIP standards and to revise format to use RBS Template.    |
| 5    | 11/22/13 | FERC Order issued approving CIP-007-5. (Order becomes effective on 2/3/14.) |  |
| 5(X) | TBD      | Adopted by the NERC Board of Trustees                                       | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Cyber Security — System Security Management
2. **Number:** CIP-007-5(X)
3. **Purpose:** To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**

**4.1.7 Transmission Operator**

**4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-007-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.



**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-007-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-007-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-007-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies**, . . .

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept

from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System in the applicability column. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

## B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in CIP-007-5(X) Table R1 – Ports and Services. *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations.]*
- M1.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in CIP-007-5(X) Table R1 – Ports and Services and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-007-5(X) Table R1– Ports and Services |   |   |  |
|---|---|---|--|
| Part                                      | Applicable Systems  | Requirements  | Measures   |
| 1.1                                       | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Documentation of the need for all enabled ports on all applicable Cyber Assets and Electronic Access Points, individually or by group.</li> <li>• Listings of the listening ports on the Cyber Assets, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or</li> <li>• Configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others.</li> </ul> |
| 1.2                                       | <p>High Impact BES Cyber Systems</p> <p>Medium Impact BES Cyber Systems at Control Centers</p>  | <p>Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or removable media.</p>  | <p>An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either logically through system configuration or physically using a port lock or signage.</p>  |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R2 – Security Patch Management

| Part | Applicable Systems  | Requirements   | Measures  |
|------|---|--|---|
| 2.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>A patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets. The tracking portion shall include the identification of a source or sources that the Responsible Entity tracks for the release of cyber security patches for applicable Cyber Assets that are updateable and for which a patching source exists.</p> | <p>An example of evidence may include, but is not limited to, documentation of a patch management process and documentation or lists of sources that are monitored, whether on an individual BES Cyber System or Cyber Asset basis.</p> |

CIP-007-5(X) Table R2 – Security Patch Management

| Part | Applicable Systems  | Requirements  | Measures   |
|------|---|---|--|
| 2.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>At least once every 35 calendar days, evaluate security patches for applicability that have been released since the last evaluation from the source or sources identified in Part 2.1.</p> | <p>An example of evidence may include, but is not limited to, an evaluation conducted by, referenced by, or on behalf of a Responsible Entity of security-related patches released by the documented sources at least once every 35 calendar days.</p> |



CIP-007-5(X) Table R2 – Security Patch Management

| Part | Applicable Systems  | Requirements  | Measures   |
|------|---|---|--|
| 2.3  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For applicable patches identified in Part 2.2, within 35 calendar days of the evaluation completion, take one of the following actions:</p> <ul style="list-style-type: none"> <li>• Apply the applicable patches; or</li> <li>• Create a dated mitigation plan; or</li> <li>• Revise an existing mitigation plan.</li> </ul> <p>Mitigation plans shall include the Responsible Entity’s planned actions to mitigate the vulnerabilities addressed by each security patch and a timeframe to complete these mitigations.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records of the installation of the patch (e.g., exports from automated patch management tools that provide installation date, verification of BES Cyber System Component software revision, or registry exports that show software has been installed); or</li> <li>• A dated plan showing when and how the vulnerability will be addressed, to include documentation of the actions to be taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch and a timeframe for the completion of these mitigations.</li> </ul> |

| CIP-007-5(X) Table R2 – Security Patch Management |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 2.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For each mitigation plan created or revised in Part 2.3, implement the plan within the timeframe specified in the plan, unless a revision to the plan or an extension to the timeframe specified in Part 2.3 is approved by the CIP Senior Manager or delegate.</p> | <p>An example of evidence may include, but is not limited to, records of implementation of mitigations.</p> |

**R3.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations].

**M3.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

**CIP-007-5(X) Table R3 – Malicious Code Prevention**

| Part | Applicable Systems  | Requirements   | Measures  |
|------|---|--|---|
| 3.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Deploy method(s) to deter, detect, or prevent malicious code.</p> | <p>An example of evidence may include, but is not limited to, records of the Responsible Entity’s performance of these processes (e.g., through traditional antivirus, system hardening, policies, etc.).</p> |

| CIP-007-5(X) Table R3 – Malicious Code Prevention |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 3.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | Mitigate the threat of detected malicious code.  | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records of response processes for malicious code detection</li> <li>• Records of the performance of these processes when malicious code is detected.</li> </ul> |
| 3.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | For those methods identified in Part 3.1 that use signatures or patterns, have a process for the update of the signatures or patterns. The process must address testing and installing the signatures or patterns. | An example of evidence may include, but is not limited to, documentation showing the process used for the update of signatures or patterns.   |

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Assessment.]
- M4.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-007-5(X) Table R4 – Security Event Monitoring |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 4.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Log events at the BES Cyber System level (per BES Cyber System capability) or at the Cyber Asset level (per Cyber Asset capability) for identification of, and after-the-fact investigations of, Cyber Security Incidents that includes, as a minimum, each of the following types of events:</p> <ol style="list-style-type: none"> <li>4.1.1. Detected successful login attempts;</li> <li>4.1.2. Detected failed access attempts and failed login attempts;</li> <li>4.1.3. Detected malicious code.</li> </ol> | <p>Examples of evidence may include, but are not limited to, a paper or system generated listing of event types for which the BES Cyber System is capable of detecting and, for generated events, is configured to log. This listing must include the required types of events.</p> |

CIP-007-5(X) Table R4 – Security Event Monitoring

| Part | Applicable Systems  | Requirements  | Measures   |
|------|---|---|--|
| 4.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Generate alerts for security events that the Responsible Entity determines necessitates an alert, that includes, as a minimum, each of the following types of events (per Cyber Asset or BES Cyber System capability):</p> <ol style="list-style-type: none"> <li>4.2.1. Detected malicious code from Part 4.1; and</li> <li>4.2.2. Detected failure of Part 4.1 event logging.</li> </ol> | <p>Examples of evidence may include, but are not limited to, paper or system-generated listing of security events that the Responsible Entity determined necessitate alerts, including paper or system generated list showing how alerts are configured.</p> |

| CIP-007-5(X) Table R4 – Security Event Monitoring |  |   |  |
|---|--|---|--|
| Part  | Applicable Systems   | Requirements  | Measures   |
| 4.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, retain applicable event logs identified in Part 4.1 for at least the last 90 consecutive calendar days except under CIP Exceptional Circumstances.</p>             | <p>Examples of evidence may include, but are not limited to, documentation of the event log retention process and paper or system generated reports showing log retention configuration set at 90 days or greater.</p> |
| 4.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol>   | <p>Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 calendar days to identify undetected Cyber Security Incidents.</p> | <p>Examples of evidence may include, but are not limited to, documentation describing the review, any findings from the review (if any), and dated documentation showing the review occurred.</p>                      |

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R5 – System Access Controls*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M5.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table 5 – System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

**CIP-007-5(X) Table R5 – System Access Control**

| Part | Applicable Systems  | Requirements  | Measures  |
|------|---|---|---|
| 5.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Have a method(s) to enforce authentication of interactive user access, where technically feasible.</p> | <p>An example of evidence may include, but is not limited to, documentation describing how access is authenticated.</p> |



| CIP-007-5(X) Table R5 – System Access Control |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 5.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Identify and inventory all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s).</p> | <p>An example of evidence may include, but is not limited to, a listing of accounts by account types showing the enabled or generic account types in use for the BES Cyber System.</p> |

| CIP-007-5(X) Table R5 – System Access Control |   |   |  |
|---|---|---|--|
| Part  | Applicable Systems  | Requirements  | Measures   |
| 5.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | Identify individuals who have authorized access to shared accounts. | An example of evidence may include, but is not limited to, listing of shared accounts and the individuals who have authorized access to each shared account. |

CIP-007-5(X) Table R5 – System Access Control

| Part | Applicable Systems  | Requirements  | Measures   |
|------|---|---|--|
| 5.4  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Change known default passwords, per Cyber Asset capability</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records of a procedure that passwords are changed when new devices are in production; or</li> <li>• Documentation in system manuals or other vendor documents showing default vendor passwords were generated pseudo-randomly and are thereby unique to the device.</li> </ul> |

| CIP-007-5(X) Table R5 – System Access Control |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 5.5   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For password-only authentication for interactive user access, either technically or procedurally enforce the following password parameters:</p> <ol style="list-style-type: none"> <li>5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the Cyber Asset; and</li> <li>5.5.2. Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the Cyber Asset.</li> </ol> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• System-generated reports or screen-shots of the system-enforced password parameters, including length and complexity; or</li> <li>• Attestations that include a reference to the documented procedures that were followed.</li> </ul> |

CIP-007-5(X) Table R5 – System Access Control

| Part | Applicable Systems  | Requirements   | Measures   |
|------|---|--|--|
| 5.6  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 calendar months.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• System-generated reports or screen-shots of the system-enforced periodicity of changing passwords; or</li> <li>• Attestations that include a reference to the documented procedures that were followed.</li> </ul> |

| CIP-007-5(X) Table R5 – System Access Control |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 5.7   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Where technically feasible, either:</p> <ul style="list-style-type: none"> <li>• Limit the number of unsuccessful authentication attempts; or</li> <li>• Generate alerts after a threshold of unsuccessful authentication attempts.</li> </ul> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Documentation of the account-lockout parameters; or</li> <li>• Rules in the alerting configuration showing how the system notified individuals after a determined number of unsuccessful login attempts.</li> </ul> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.



**2. Table of Compliance Elements**

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X)) |   |   |   |
|-----------|----------------------------|---------------|--|---|---|---|
|           |                            |               | Lower VSL                                | Moderate VSL  | High VSL  | Severe VSL  |
| <b>R1</b> | <b>Same Day Operations</b> | <b>Medium</b> | N/A                                      | <p>The Responsible Entity has implemented and documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media and has identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has implemented and</p> | <p>The Responsible Entity has implemented and documented processes for determining necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented and documented processes for determining</p> | <p>The Responsible Entity has implemented and documented processes for determining necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled and has identified deficiencies but did not assess or correct the deficiencies. (R1)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R1 but did not</p> |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X))   |  |  |  |
|-----------|----------------------------|---------------|--|--|--|--|
|           |                            |               | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|           |                            |               |  | documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media but did not identify, assess, or correct the deficiencies. (1.2) | necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled but did not identify, assess, or correct the deficiencies. (1.1) | identify, assess, or correct the deficiencies. (R1)  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Medium</b> | The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the | The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of   | The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for                    | The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 and has identified deficiencies but did |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))   |   |  |  |
|-----|--------------|-----|--|---|--|--|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
|     |              |     | <p>security patches for applicability within 35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within</p> | <p>sources, for tracking or evaluating cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of sources, for tracking, or evaluating cyber security patches for applicable Cyber Assets but did not</p> | <p>applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for applicable Cyber Assets but did not identify, assess, or correct the deficiencies. (2.1)</p> <p>OR</p> | <p>not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 but did not identify, assess, or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |  |  |
|-----|--------------|-----|---|---|--|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|     |              |     | <p>35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an</p> | <p>identify, assess, or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct</p> | <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or</p> | <p>tracking, evaluating, or installing cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for tracking, evaluating, or installing cyber security patches for applicable Cyber Assets but did not identify, assess, or</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a</p> | <p>the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> | <p>more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the days source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by</p> | <p>correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate and has identified deficiencies but did not assess or correct the deficiencies. (2.4)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | dated mitigation plan, or revise an existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3) | OR<br>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct | applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3)<br>OR<br>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by | an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate but did not identify, assess, or correct the deficiencies. (2.4)<br>OR<br>The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan and has identified deficiencies but did |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     |  | the deficiencies. (2.3)<br>OR<br>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion but did not identify, assess, | applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3) | not assess or correct the deficiencies. (2.4)<br>OR<br>The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan but did not identify, assess, or correct the deficiencies. (2.4) |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X)) |  |  |   |
|-----------|----------------------------|---------------|--|--|--|---|
|           |                            |               | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL  |
|           |                            |               |  | or correct the deficiencies. (2.3)   |  |   |
| <b>R3</b> | <b>Same Day Operations</b> | <b>Medium</b> |  | <p>The Responsible Entity has implemented one or more documented process(es), but, where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and has identified deficiencies but did not assess or correct the deficiencies. (3.3)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es), but,</p> | <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected</p> | <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R3 and has identified deficiencies but did not assess or correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     |  | <p>where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and did not identify, assess, or correct the deficiencies. (3.3)</p> | <p>malicious code and did not identify, assess, or correct the deficiencies. (3.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and has identified deficiencies but did not assess or correct the deficiencies. (3.3)</p> <p>OR</p> | <p>R3 and did not identify, assess, or correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or</p> |

| R #       | Time Horizon   | VRF           | Violation Severity Levels (CIP-007-5(X))  |   |   |   |
|-----------|--|---------------|---|---|---|---|
|           |  |               | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|           |  |               |   |   | The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and did not identify, assess, or correct the deficiencies. (3.3) | more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and did not identify, assess, or correct the deficiencies. (3.1) |
| <b>R4</b> | <b>Same Day Operations and Operations Assessment</b> | <b>Medium</b> | The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity- | The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity- | The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the  | The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and has  |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |   |  |
|-----|--------------|-----|---|---|---|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | <p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p> | <p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p> | <p>responsible entity) for the Applicable Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and has identified deficiencies but did not assess or correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the responsible entity) for the Applicable</p> | <p>identified deficiencies but did not assess or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and did not identify, assess, or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to log events for the</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))  |   |  |  |
|-----|--------------|-----|---|---|--|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|     |              |     | summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4) | summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4) | Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and did not identify, assess, or correct the deficiencies. (4.2)<br>OR<br>The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event | Applicable Systems (per device or system capability) but did not detect and log all of the required types of events described in 4.1.1 through 4.1.3 and has identified deficiencies but did not assess or correct the deficiencies. (4.1)<br>OR<br>The Responsible Entity has documented and implemented one or more process(es) to log events for the Applicable Systems (per device or system capability) but did not detect and log all of the required types of |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |   |
|-----|--------------|-----|--|--------------|---|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
|     |              |     |  |              | <p>logs for at least the last 90 consecutive days and has identified deficiencies but did not assess or correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event logs for at least the last 90 consecutive days and did not</p> | <p>events described in 4.1.1 through 4.1.3 and did not identify, assess, or correct the deficiencies. (4.1)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |            |
|-----|--------------|-----|--|--------------|---|------------|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL |
|     |              |     |  |              | identify, assess, or correct the deficiencies. (4.3)<br><br>OR<br><br>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and has identified deficiencies but did not assess or correct the deficiencies. (4.4) |            |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-007-5(X))  |   |  |  |
|-----------|----------------------------|---------------|---|---|--|--|
|           |                            |               | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|           |                            |               |   |   | OR<br>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and did not identify, assess, or correct the deficiencies. (4.4) |  |
| <b>R5</b> | <b>Operations Planning</b> | <b>Medium</b> | The Responsible Entity has implemented one or more documented process(es) for password-only | The Responsible Entity has implemented one or more documented process(es) for password-only | The Responsible Entity has implemented one or more documented process(es) for System Access  | The Responsible Entity did not implement or document one or more process(es) that included the |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))   |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p> | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p> | <p>Controls but, did not include the identification or inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and has identified deficiencies but did not assess or correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification or</p> | <p>applicable items in CIP-007-5(X) Table R5 and has identified deficiencies but did not assess or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R5 and did not identify, assess, or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X))   |  |  |  |
|-----|--------------|-----|--|--|--|--|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)</p> | <p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)</p> | <p>inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and did not identify, assess, or correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and has identified</p> | <p>more documented process(es) for System Access Controls but, where technically feasible, does not have a method(s) to enforce authentication of interactive user access and has identified deficiencies but did not assess or correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, where technically feasible, does not have a</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | deficiencies but did not assess or correct the deficiencies. (5.3)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and did not identify, assess, or correct the deficiencies. (5.3)<br>OR<br>The Responsible Entity has implemented one or | method(s) to enforce authentication of interactive user access and did not identify, assess, or correct the deficiencies. (5.1)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords and has identified deficiencies but did not assess or correct the deficiencies. (5.4) |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | <p>more documented process(es) for password-only authentication for interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for</p> | <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords but did not identify, assess, or correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |  |  |
|-----|--------------|-----|--|--------------|--|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL   |
|     |              |     |  |              | <p>interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to</p> | <p>did not technically or procedurally enforce all of the password parameters described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity did not technically or procedurally enforce all of the</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to | password parameters described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and has |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |   |   |
|-----|--------------|-----|--|--------------|---|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
|     |              |     |  |              | change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6) | identified deficiencies but did not assess or correct the deficiencies. (5.6)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and did not identify, assess, or |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     |  |              |          | correct the deficiencies. (5.6)<br>OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and has identified deficiencies but did not assess or correct the deficiencies. (5.7) |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-007-5(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     |  |              |          | OR<br>The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and did not identify, assess, or correct the deficiencies. (5.7) |



## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

Requirement R1 exists to reduce the attack surface of Cyber Assets by requiring entities to disable known unnecessary ports. The SDT intends for the entity to know what network accessible (“listening”) ports and associated services are accessible on their assets and systems, whether they are needed for that Cyber Asset’s function, and disable or restrict access to all other ports.

**1.1.** This requirement is most often accomplished by disabling the corresponding service or program that is listening on the port or configuration settings within the Cyber Asset. It can also be accomplished through using host-based firewalls, TCP\_Wrappers, or other means on the Cyber Asset to restrict access. Note that the requirement is applicable at the Cyber Asset level. The Cyber Assets are those which comprise the applicable BES Cyber Systems and their associated Cyber Assets. This control is another layer in the defense against network-based attacks, therefore the SDT intends that the control be on the device itself, or positioned inline in a non-bypassable manner. Blocking ports at the ESP border does not substitute for this device level requirement. If a device has no provision for disabling or restricting logical ports on the device (example - purpose built devices that run from firmware with no port configuration available) then those ports that are open are deemed ‘needed.’

**1.2.** Examples of physical I/O ports include network, serial and USB ports external to the device casing. BES Cyber Systems should exist within a Physical Security Perimeter in which

case the physical I/O ports have protection from unauthorized access, but it may still be possible for accidental use such as connecting a modem, connecting a network cable that bridges networks, or inserting a USB drive. Ports used for 'console commands' primarily means serial ports on Cyber Assets that provide an administrative interface.

The protection of these ports can be accomplished in several ways including, but not limited to:

- Disabling all unneeded physical ports within the Cyber Asset's configuration
- Prominent signage, tamper tape, or other means of conveying that the ports should not be used without proper authorization
- Physical port obstruction through removable locks

This is a 'defense in depth' type control and it is acknowledged that there are other layers of control (the PSP for one) that prevent unauthorized personnel from gaining physical access to these ports. Even with physical access, it has been pointed out there are other ways to circumvent the control. This control, with its inclusion of means such as signage, is not meant to be a preventative control against intruders. Signage is indeed a directive control, not a preventative one. However, with a defense-in-depth posture, different layers and types of controls are required throughout the standard with this providing another layer for depth in Control Center environments. Once physical access has been achieved through the other preventative and detective measures by authorized personnel, a directive control that outlines proper behavior as a last line of defense are appropriate in these highest risk areas. In essence, signage would be used to remind authorized users to "think before you plug anything into one of these systems" which is the intent. This control is not designed primarily for intruders, but for example the authorized employee who intends to plug his possibly infected smartphone into an operator console USB port to charge the battery.

### **Requirement R2:**

The SDT's intent of Requirement R2 is to require entities to know, track, and mitigate the known software vulnerabilities associated with their BES Cyber Assets. It is not strictly an "install every security patch" requirement; the main intention is to "be aware of in a timely manner and manage all known vulnerabilities" requirement.

Patch management is required for BES Cyber Systems that are accessible remotely as well as standalone systems. Stand alone systems are vulnerable to intentional or unintentional introduction of malicious code. A sound defense-in-depth security strategy employs additional measures such as physical security, malware prevention software, and software patch management to reduce the introduction of malicious code or the exploit of known vulnerabilities.

One or multiple processes could be utilized. An overall assessment process may exist in a top tier document with lower tier documents establishing the more detailed process followed for individual systems. Lower tier documents could be used to cover BES Cyber System nuances that may occur at the system level.

**2.1.** The Responsible Entity is to have a patch management program that covers tracking, evaluating, and installing cyber security patches. The requirement applies to patches only,

which are fixes released to handle a specific vulnerability in a hardware or software product. The requirement covers only patches that involve cyber security fixes and does not cover patches that are purely functionality related with no cyber security impact. Tracking involves processes for notification of the availability of new cyber security patches for the Cyber Assets. Documenting the patch source in the tracking portion of the process is required to determine when the assessment timeframe clock starts. This requirement handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system. The source can take many forms. The National Vulnerability Database, Operating System vendors, or Control System vendors could all be sources to monitor for release of security related patches, hotfixes, and/or updates. A patch source is not required for Cyber Assets that have no updateable software or firmware (there is no user accessible way to update the internal software or firmware executing on the Cyber Asset), or those Cyber Assets that have no existing source of patches such as vendors that no longer exist. The identification of these sources is intended to be performed once unless software is changed or added to the Cyber Asset's baseline.

**2.2.** Responsible Entities are to perform an assessment of security related patches within 35 days of release from their monitored source. An assessment should consist of determination of the applicability of each patch to the entity's specific environment and systems. Applicability determination is based primarily on whether the patch applies to a specific software or hardware component that the entity does have installed in an applicable Cyber Asset. A patch that applies to a service or component that is not installed in the entity's environment is not applicable. If the patch is determined to be non-applicable, that is documented with the reasons why and the entity is compliant. If the patch is applicable, the assessment can include a determination of the risk involved, how the vulnerability can be remediated, the urgency and timeframe of the remediation, and the steps the entity has previously taken or will take. Considerable care must be taken in applying security related patches, hotfixes, and/or updates or applying compensating measures to BES Cyber System or BES Cyber Assets that are no longer supported by vendors. It is possible security patches, hotfixes, and updates may reduce the reliability of the system, and entities should take this into account when determining the type of mitigation to apply. The Responsible Entities can use the information provided in the Department of Homeland Security "Quarterly Report on Cyber Vulnerabilities of Potential Risk to Control Systems" as a source. The DHS document "Recommended Practice for Patch Management of Control Systems" provides guidance on an evaluative process. It uses severity levels determined using the Common Vulnerability Scoring System Version 2. Determination that a security related patch, hotfix, and/or update poses too great a risk to install on a system or is not applicable due to the system configuration should not require a TFE.

When documenting the remediation plan measures it may not be necessary to document them on a one to one basis. The remediation plan measures may be cumulative. A measure to address a software vulnerability may involve disabling a particular service. That same service may be exploited through other software vulnerabilities. Therefore disabling the single service has addressed multiple patched vulnerabilities.

**2.3.** The requirement handles the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity either installs the patch or documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. There are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability. For those security related patches that are determined to be applicable, the Responsible Entity must within 35 days either install the patch, create a dated mitigation plan which will outline the actions to be taken or those that have already been taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch, or revise an existing mitigation plan. Timeframes do not have to be designated as a particular calendar day but can have event designations such as “at next scheduled outage of at least two days duration.” “Mitigation plans” in the standard refers to internal documents and are not to be confused with plans that are submitted to Regional Entities in response to violations.

**2.4.** The entity has been notified of, has assessed, and has developed a plan to remediate the known risk and that plan must be implemented. Remediation plans that only include steps that have been previously taken are considered implemented upon completion of the documentation. Remediation plans that have steps to be taken to remediate the vulnerability must be implemented by the timeframe the entity documented in their plan. There is no maximum timeframe in this requirement as patching and other system changes carries its own risk to the availability and integrity of the systems and may require waiting until a planned outage. In periods of high demand or threatening weather, changes to systems may be curtailed or denied due to the risk to reliability.

**Requirement R3:**

**3.1.** Due to the wide range of equipment comprising the BES Cyber Systems and the wide variety of vulnerability and capability of that equipment to malware as well as the constantly evolving threat and resultant tools and controls, it is not practical within the standard to prescribe how malware is to be addressed on each Cyber Asset. Rather, the Responsible Entity determines on a BES Cyber System basis which Cyber Assets have susceptibility to malware intrusions and documents their plans and processes for addressing those risks and provides evidence that they follow those plans and processes. There are numerous options available including traditional antivirus solutions for common operating systems, white-listing solutions, network isolation techniques, portable storage media policies, Intrusion Detection/Prevention (IDS/IPS) solutions, etc. If an entity has numerous BES Cyber Systems or Cyber Assets that are of identical architecture, they may provide one process that describes how all the like Cyber Assets are covered. If a specific Cyber Asset has no updateable software and its executing code cannot be altered, then that Cyber Asset is considered to have its own internal method of deterring malicious code.

**3.2.** When malicious code is detected on a Cyber Asset within the applicability of this requirement, the threat posed by that code must be mitigated. In situations where traditional antivirus products are used, they may be configured to automatically remove or quarantine the malicious code. In white-listing situations, the white-listing tool itself can mitigate the threat as

it will not allow the code to execute, however steps should still be taken to remove the malicious code from the Cyber Asset. In some instances, it may be in the best interest of reliability to not immediately remove or quarantine the malicious code, such as when availability of the system may be jeopardized by removal while operating and a rebuild of the system needs to be scheduled. In that case, monitoring may be increased and steps taken to insure the malicious code cannot communicate with other systems. In some instances the entity may be working with law enforcement or other governmental entities to closely monitor the code and track the perpetrator(s). For these reasons, there is no maximum timeframe or method prescribed for the removal of the malicious code, but the requirement is to mitigate the threat posed by the now identified malicious code.

**3.3.** In instances where malware detection technologies depend on signatures or patterns of known attacks, the effectiveness of these tools against evolving threats is tied to the ability to keep these signatures and patterns updated in a timely manner. The entity is to have a documented process that includes the testing and installation of signature or pattern updates. In a BES Cyber System, there may be some Cyber Assets that would benefit from the more timely installation of the updates where availability of that Cyber Asset would not jeopardize the availability of the BES Cyber System's ability to perform its function. For example, some HMI workstations where portable media is utilized may benefit from having the very latest updates at all times with minimal testing. Other Cyber Assets should have any updates thoroughly tested before implementation where the result of a 'false positive' could harm the availability of the BES Cyber System. The testing should not negatively impact the reliability of the BES. The testing should be focused on the update itself and if it will have an adverse impact on the BES Cyber System. Testing in no way implies that the entity is testing to ensure that malware is indeed detected by introducing malware into the environment. It is strictly focused on ensuring that the update does not negatively impact the BES Cyber System before those updates are placed into production.

**Requirement R4:**

Refer to NIST 800-92 and 800-137 for additional guidance in security event monitoring.

**4.1.** In a complex computing environment and faced with dynamic threats and vulnerabilities, it is not practical within the standard to enumerate all security-related events necessary to support the activities for alerting and incident response. Rather, the Responsible Entity determines which computer generated events are necessary to log, provide alerts and monitor for their particular BES Cyber System environment.

Specific security events already required in Version 4 of the CIP Standards carry forward in this version. This includes access attempts at the Electronic Access Points, if any have been identified for a BES Cyber Systems. Examples of access attempts include: (i) blocked network access attempts, (ii) successful and unsuccessful remote user access attempts, (iii) blocked network access attempts from a remote VPN, and (iv) successful network access attempts or network flow information.

User access and activity events include those events generated by Cyber Assets within the Electronic Security Perimeter that have access control capability. These types of events include:

(i) successful and unsuccessful authentication, (ii) account management, (iii) object access, and (iv) processes started and stopped.

It is not the intent of the SDT that if a device cannot log a particular event that a TFE must be generated. The SDT's intent is that if any of the items in the bulleted list (for example, user logouts) can be logged by the device then the entity must log that item. If the device does not have the capability of logging that event, the entity remains compliant.

**4.2.** Real-time alerting allows the cyber system to automatically communicate events of significance to designated responders. This involves configuration of a communication mechanism and log analysis rules. Alerts can be configured in the form of an email, text message, or system display and alarming. The log analysis rules can exist as part of the operating system, specific application or a centralized security event monitoring system. On one end, a real-time alert could consist of a set point on an RTU for a login failure, and on the other end, a security event monitoring system could provide multiple alerting communications options triggered on any number of complex log correlation rules.

The events triggering a real-time alert may change from day to day as system administrators and incident responders better understand the types of events that might be indications of a cyber-security incident. Configuration of alerts also must balance the need for responders to know an event occurred with the potential inundation of insignificant alerts. The following list includes examples of events a Responsible Entity should consider in configuring real-time alerts:

- Detected known or potential malware or malicious activity
- Failure of security event logging mechanisms
- Login failures for critical accounts
- Interactive login of system accounts
- Enabling of accounts
- Newly provisioned accounts
- System administration or change tasks by an unauthorized user
- Authentication attempts on certain accounts during non-business hours
- Unauthorized configuration changes
- Insertion of removable media in violation of a policy

**4.3** Logs that are created under Part 4.1 are to be retained on the applicable Cyber Assets or BES Cyber Systems for at least 90 days. This is different than the evidence retention period called for in the CIP standards used to prove historical compliance. For such audit purposes, the entity should maintain evidence that shows that 90 days were kept historically. One example would be records of disposition of event logs beyond 90 days up to the evidence retention period.

**4.4.** Reviewing logs at least every 15 days (approximately every two weeks) can consist of analyzing a summarization or sampling of logged events. NIST SP800-92 provides a lot of guidance in periodic log analysis. If a centralized security event monitoring system is used, log analysis can be performed top-down starting with a review of trends from summary reports.

The log review can also be an extension of the exercise in identifying those events needing real-time alerts by analyzing events that are not fully understood or could possibly inundate the real-time alerting.

### **Requirement R5:**

Account types referenced in this guidance typically include:

- **Shared user account:** An account used by multiple users for normal business functions by employees or contractors. Usually on a device that does not support Individual User Accounts.
- **Individual user account:** An account used by a single user.
- **Administrative account:** An account with elevated privileges for performing administrative or other specialized functions. These can be individual or shared accounts.
- **System account:** Accounts used to run services on a system (web, DNS, mail etc). No users have access to these accounts.
- **Application account:** A specific system account, with rights granted at the application level often used for access into a Database.
- **Guest account:** An individual user account not typically used for normal business functions by employees or contractors and not associated with a specific user. May or may not be shared by multiple users.
- **Remote access account:** An individual user account only used for obtaining Interactive Remote Access to the BES Cyber System.
- **Generic account:** A group account set up by the operating system or application to perform specific operations. This differs from a shared user account in that individual users do not receive authorization for access to this account type.

**5.1** Reference the Requirement's rationale.

**5.2** Where possible, default and other generic accounts provided by a vendor should be removed, renamed, or disabled prior to production use of the Cyber Asset or BES Cyber System. If this is not possible, the passwords must be changed from the default provided by the vendor. Default and other generic accounts remaining enabled must be documented. For common configurations, this documentation can be performed at a BES Cyber System or more general level.

**5.3** Entities may choose to identify individuals with access to shared accounts through the access authorization and provisioning process, in which case the individual authorization records suffice to meet this Requirement Part. Alternatively, entities may choose to maintain a separate listing for shared accounts. Either form of evidence achieves the end result of maintaining control of shared accounts.

**5.4.** Default passwords can be commonly published in vendor documentation that is readily available to all customers using that type of equipment and possibly published online.

The requirement option to have unique password addresses cases where the Cyber Asset generates or has assigned pseudo-random default passwords at the time of production or installation. In these cases, the default password does not have to change because the system or manufacturer created it specific to the Cyber Asset.

**5.5.** Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Technical or procedural enforcement of password parameters are required where passwords are the only credential used to authenticate individuals. Technical enforcement of the password parameters means a Cyber Asset verifies an individually selected password meets the required parameters before allowing the account to authenticate with the selected password. Technical enforcement should be used in most cases when the authenticating Cyber Asset supports enforcing password parameters. Likewise, procedural enforcement means requiring the password parameters through procedures. Individuals choosing the passwords have the obligation of ensuring the password meets the required parameters.

Password complexity refers to the policy set by a Cyber Asset to require passwords to have one or more of the following types of characters: (1) lowercase alphabetic, (2) uppercase alphabetic, (3) numeric, and (4) non-alphanumeric or “special” characters (e.g. #, \$, @, &), in various combinations.

**5.6** Technical or procedural enforcement of password change obligations are required where passwords are the only credential used to authenticate individuals. Technical enforcement of password change obligations means the Cyber Asset requires a password change after a specified timeframe prior to allowing access. In this case, the password is not required to change by the specified time as long as the Cyber Asset enforces the password change after the next successful authentication of the account. Procedural enforcement means manually changing passwords used for interactive user access after a specified timeframe.

**5.7** Configuring an account lockout policy or alerting after a certain number of failed authentication attempts serves to prevent unauthorized access through an online password guessing attack. The threshold of failed authentication attempts should be set high enough to avoid false-positives from authorized users failing to authenticate. It should also be set low enough to account for online password attacks occurring over an extended period of time. This threshold may be tailored to the operating environment over time to avoid unnecessary account lockouts.

Entities should take caution when configuring account lockout to avoid locking out accounts necessary for the BES Cyber System to perform a BES reliability task. In such cases, entities should configure authentication failure alerting.



## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

The requirement is intended to minimize the attack surface of BES Cyber Systems through disabling or limiting access to unnecessary network accessible logical ports and services and physical I/O ports.

**Summary of Changes:** Changed the ‘needed for normal or emergency operations’ to those ports that are needed. Physical I/O ports were added in response to a FERC order. The unneeded physical ports in Control Centers (which are the highest risk, most impactful areas) should be protected as well.

**Reference to prior version:** (Part 1.1) CIP-007-4, R2.1 and R2.2

**Change Rationale:** (Part 1.1)

*The requirement focuses on the entity knowing and only allowing those ports that are necessary. The additional classification of ‘normal or emergency’ added no value and has been removed.*

**Reference to prior version:** (Part 1.2) New

**Change Rationale:** (Part 1.2)

*On March 18, 2010, FERC issued an order to approve NERC’s interpretation of Requirement R2 of CIP-007-2. In this order, FERC agreed the term “ports” in “ports and services” refers to logical communication (e.g. TCP/IP) ports, but they also encouraged the drafting team to address unused physical ports.*

### **Rationale for R2:**

Security patch management is a proactive way of monitoring and addressing known security vulnerabilities in software before those vulnerabilities can be exploited in a malicious manner to gain control of or render a BES Cyber Asset or BES Cyber System inoperable.

The remediation plan can be updated as necessary to maintain the reliability of the BES, including an explanation of any rescheduling of the remediation actions.

**Summary of Changes:** The existing wordings of CIP-007, Requirements R3, R3.1, and R3.2, were separated into individual line items to provide more granularity. The documentation of a source(s) to monitor for release of security related patches, hot fixes, and/or updates for BES Cyber System or BES Cyber Assets was added to provide context as to when the “release” date was. The current wording stated “document the assessment of security patches and security

upgrades for applicability within thirty calendar days of availability of the patches or upgrades” and there has been confusion as to what constitutes the availability date. Due to issues that may occur regarding Control System vendor license and service agreements, flexibility must be given to Responsible Entities to define what sources are being monitored for BES Cyber Assets.

**Reference to prior version:** (Part 2.1) CIP-007, R3

**Change Rationale:** (Part 2.1)

*The requirement is brought forward from previous CIP versions with the addition of defining the source(s) that a Responsible Entity monitors for the release of security related patches. Documenting the source is used to determine when the assessment timeframe clock starts. This requirement also handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system.*

**Reference to prior version:** (Part 2.2) CIP-007, R3.1

**Change Rationale:** (Part 2.2)

*Similar to the current wording but added “from the source or sources identified in 2.1” to clarify the 35-day time frame.*

**Reference to prior version:** (Part 2.3) CIP-007, R3.2

**Change Rationale:** (Part 2.3)

*The requirement has been changed to handle the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. The mitigation plan may, and in many cases will, consist of installing the patch. However, there are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability.*

**Reference to prior version:** (Part 2.4) CIP-007, R3.2

**Change Rationale:** (Part 2.4)

*Similar to the current wording but added that the plan must be implemented within the timeframe specified in the plan, or in a revised plan as approved by the CIP Senior Manager or delegate.*

**Rationale for R3:**

Malicious code prevention has the purpose of limiting and detecting the addition of malicious code onto the applicable Cyber Assets of a BES Cyber System. Malicious code (viruses, worms, botnets, targeted code such as Stuxnet, etc.) may compromise the availability or integrity of the BES Cyber System.

**Summary of Changes:** In prior versions, this requirement has arguably been the single greatest generator of TFEs as it prescribed a particular technology to be used on every CCA regardless of

that asset's susceptibility or capability to use that technology. As the scope of Cyber Assets in scope of these standards expands to more field assets, this issue will grow exponentially. The drafting team is taking the approach of making this requirement a competency based requirement where the entity must document how the malware risk is handled for each BES Cyber System, but it does not prescribe a particular technical method nor does it prescribe that it must be used on every Cyber Asset. The BES Cyber System is the object of protection.

Beginning in Paragraphs 619-622 of FERC Order No. 706, and in particular Paragraph 621, FERC agrees that the standard "does not need to prescribe a single method...However, how a responsible entity does this should be detailed in its cyber security policy so that it can be audited for compliance..."

In Paragraph 622, FERC directs that the requirement be modified to include safeguards against personnel introducing, either maliciously or unintentionally, viruses or malicious software through remote access, electronic media, or other means. The drafting team believes that addressing this issue holistically at the BES Cyber System level and regardless of technology, along with the enhanced change management requirements, meets this directive.

**Reference to prior version:** (Part 3.1) CIP-007-4, R4; CIP-007-4, R4.1

**Change Rationale:** (Part 3.1)

*See the Summary of Changes. FERC Order No. 706, Paragraph 621, states the standards development process should decide to what degree to protect BES Cyber Systems from personnel introducing malicious software.*

**Reference to prior version:** (Part 3.2) CIP-007-4, R4; CIP-007-4, R4.1

**Change Rationale:** (Part 3.2)

*See the Summary of Changes.*

**Reference to prior version:** (Part 3.3) CIP-007-4, R4; CIP-007-4, R4.2

**Change Rationale:** (Part 3.3)

*Requirement essentially unchanged from previous versions; updated to refer to previous parts of the requirement table.*

#### **Rationale for R4:**

**Rationale for R4:** Security event monitoring has the purpose of detecting unauthorized access, reconnaissance and other malicious activity on BES Cyber Systems, and comprises of the activities involved with the collection, processing, alerting and retention of security-related computer logs. These logs can provide both (1) the detection of an incident and (2) useful evidence in the investigation of an incident. The retention of security-related logs is intended to support post-event data analysis.

Audit processing failures are not penalized in this requirement. Instead, the requirement specifies processes which must be in place to monitor for and notify personnel of audit processing failures.

**Summary of Changes:** Beginning in Paragraph 525 and also Paragraph 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis. This requirement combines CIP-005-4, R5 and CIP-007-4, R6 and addresses both directives from a system-wide perspective. The primary feedback received on this requirement from the informal comment period was the vagueness of terms “security event” and “monitor.”

The term “security event” or “events related to cyber security” is problematic because it does not apply consistently across all platforms and applications. To resolve this term, the requirement takes an approach similar to NIST 800-53 and requires the entity to define the security events relevant to the System. There are a few events explicitly listed that if a Cyber Asset or BES Cyber System can log, then it must log.

In addition, this requirement sets up parameters for the monitoring and reviewing of processes. It is rarely feasible or productive to look at every security log on the system. Paragraph 629 of the FERC Order No. 706 acknowledges this reality when directing a manual log review. As a result, this requirement allows the manual review to consist of a sampling or summarization of security events occurring since the last review.

**Reference to prior version:** (Part 4.1) CIP-005-4, R3; CIP-007-4, R5, R5.1.2, R6.1, and R6.3

**Change Rationale:** (Part 4.1)

*This requirement is derived from NIST 800-53 version 3 AU-2, which requires organizations to determine system events to audit for incident response purposes. The industry expressed confusion in the term “system events related to cyber security” from informal comments received on CIP-011. Access logs from the ESP as required in CIP-005-4 Requirement R3 and user access and activity logs as required in CIP-007-5 Requirement R5 are also included here.*

**Reference to prior version:** (Part 4.2) CIP-005-4, R3.2; CIP-007-4, R6.2

**Change Rationale:** (Part 4.2)

*This requirement is derived from alerting requirements in CIP-005-4, Requirement R3.2 and CIP-007-4, Requirement R6.2 in addition to NIST 800-53 version 3 AU-6. Previous CIP Standards required alerting on unauthorized access attempts and detected Cyber Security Incidents, which can be vast and difficult to determine from day to day. Changes to this requirement allow the entity to determine events that necessitate a response.*

**Reference to prior version:** (Part 4.3) CIP-005-4, R3.2; CIP-007-4, R6.4

**Change Rationale:** (Part 4.3)

*No substantive change.*

**Reference to prior version:** (Part 4.4) CIP-005-4, R3.2; CIP-007-4, R6.5

**Change Rationale:** (Part 4.4)

*Beginning in Paragraph 525 and also 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis and suggests a weekly review. The Order acknowledges it is rarely feasible to review all system logs. Indeed, log review is a dynamic process that should improve over time and with additional threat information.*

*Changes to this requirement allow for an approximately biweekly summary or sampling review of logs.*

**Rationale for R5:**

To help ensure that no authorized individual can gain electronic access to a BES Cyber System until the individual has been authenticated, i.e., until the individual's logon credentials have been validated. Requirement R5 also seeks to reduce the risk that static passwords, where used as authenticators, may be compromised.

Requirement Part 5.1 ensures the BES Cyber System or Cyber Asset authenticates individuals that can modify configuration information. This requirement addresses the configuration of authentication. The authorization of individuals is addressed elsewhere in the CIP Cyber Security Standards. Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Requirement Part 5.2 addresses default and other generic account types. Identifying the use of default or generic account types that could introduce vulnerabilities has the benefit ensuring entities understand the possible risk these accounts pose to the BES Cyber System. The Requirement Part avoids prescribing an action to address these accounts because the most effective solution is situation specific, and in some cases, removing or disabling the account could have reliability consequences.

Requirement Part 5.3 addresses identification of individuals with access to shared accounts. This Requirement Part has the objective of mitigating the risk of unauthorized access through shared accounts. This differs from other CIP Cyber Security Standards Requirements to authorize access. An entity can authorize access and still not know who has access to a shared account. Failure to identify individuals with access to shared accounts would make it difficult to revoke access when it is no longer needed. The term "authorized" is used in the requirement to make clear that individuals storing, losing, or inappropriately sharing a password is not a violation of this requirement.

Requirement 5.4 addresses default passwords. Changing default passwords closes an easily exploitable vulnerability in many systems and applications. Pseudo-randomly system generated passwords are not considered default passwords.

For password-based user authentication, using strong passwords and changing them periodically helps mitigate the risk of successful password cracking attacks and the risk of accidental password disclosure to unauthorized individuals. In these requirements, the drafting team considered multiple approaches to ensuring this requirement was both effective and flexible enough to allow Responsible Entities to make good security decisions. One of the approaches considered involved requiring minimum password entropy, but the calculation for

true information entropy is more highly complex and makes several assumptions in the passwords users choose. Users can pick poor passwords well below the calculated minimum entropy.

The drafting team also chose to not require technical feasibility exceptions for devices that cannot meet the length and complexity requirements in password parameters. The objective of this requirement is to apply a measurable password policy to deter password cracking attempts, and replacing devices to achieve a specified password policy does not meet this objective. At the same time, this requirement has been strengthened to require account lockout or alerting for failed login attempts, which in many instances better meets the requirement objective.

The requirement to change passwords exists to address password cracking attempts if an encrypted password were somehow attained and also to refresh passwords which may have been accidentally disclosed over time. The requirement permits the entity to specify the periodicity of change to accomplish this objective. Specifically, the drafting team felt determining the appropriate periodicity based on a number of factors is more effective than specifying the period for every BES Cyber System in the Standard. In general, passwords for user authentication should be changed at least annually. The periodicity may increase in some cases. For example, application passwords that are long and pseudo-randomly generated could have a very long periodicity. Also, passwords used only as a weak form of application authentication, such as accessing the configuration of a relay may only need to be changed as part of regularly scheduled maintenance.

The Cyber Asset should automatically enforce the password policy for individual user accounts. However, for shared accounts in which no mechanism exists to enforce password policies, the Responsible Entity can enforce the password policy procedurally and through internal assessment and audit.

Requirement Part 5.7 assists in preventing online password attacks by limiting the number of guesses an attacker can make. This requirement allows either limiting the number of failed authentication attempts or alerting after a defined number of failed authentication attempts. Entities should take caution in choosing to limit the number of failed authentication attempts for all accounts because this would allow the possibility for a denial of service attack on the BES Cyber System.

### **Summary of Changes (From R5):**

CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. For example, many have interpreted the password for tokens or biometrics must satisfy this policy and in some cases prevents the use of this stronger authentication. Also, longer passwords may preclude the use of strict complexity requirements. The password requirements have been changed to allow the entity to specify the most effective password parameters based on the impact of the BES Cyber System, the way passwords are used, and the significance of passwords in restricting access to the system. The SDT believes these changes strengthen the authentication

mechanism by requiring entities to look at the most effective use of passwords in their environment. Otherwise, prescribing a strict password policy has the potential to limit the effectiveness of security mechanisms and preclude better mechanisms in the future.

**Reference to prior version:** (Part 5.1) CIP-007-4, R5

**Change Rationale:** (Part 5.1)

*The requirement to enforce authentication for all user access is included here. The requirement to establish, implement, and document controls is included in this introductory requirement. The requirement to have technical and procedural controls was removed because technical controls suffice when procedural documentation is already required. The phrase “that minimize the risk of unauthorized access” was removed and more appropriately captured in the rationale statement.*

**Reference to prior version:** (Part 5.2) CIP-007-4, R5.2 and R5.2.1

**Change Rationale:** (Part 5.2)

*CIP-007-4 requires entities to minimize and manage the scope and acceptable use of account privileges. The requirement to minimize account privileges has been removed because the implementation of such a policy is difficult to measure at best.*

**Reference to prior version:** (Part 5.3) CIP-007-4, R5.2.2

**Change Rationale:** (Part 5.3)

*No significant changes. Added “authorized” access to make clear that individuals storing, losing or inappropriately sharing a password is not a violation of this requirement.*

**Reference to prior version:** (Part 5.4) CIP-007-4, R5.2.1

**Change Rationale:** (Part 5.4)

*The requirement for the “removal, disabling or renaming of such accounts where possible” has been removed and incorporated into guidance for acceptable use of account types. This was removed because those actions are not appropriate on all account types. Added the option of having unique default passwords to permit cases where a system may have generated a default password or a hard-coded uniquely generated default password was manufactured with the BES Cyber System.*

**Reference to prior version:** (Part 5.5) CIP-007-4, R5.3

**Change Rationale:** (Part 5.5)

*CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. The password requirements have been changed to permit the maximum allowed by the device in cases where the password parameters could otherwise not achieve a stricter policy. This change still achieves the requirement objective to minimize the risk of unauthorized disclosure of password*

*credentials while recognizing password parameters alone do not achieve this. The drafting team felt allowing the Responsible Entity the flexibility of applying the strictest password policy allowed by a device outweighed the need to track a relatively minimally effective control through the TFE process.*

**Reference to prior version:** (Part 5.6) CIP-007-4, R5.3.3

**Change Rationale:** (Part 5.6)

*\*This was originally Requirement R5.5.3, but moved to add “external routable connectivity” to medium impact in response to comments. This requirement is limited in scope because the risk to performing an online password attack is lessened by its lack of external routable connectivity. Frequently changing passwords at field assets can entail significant effort with minimal risk reduction.*

**Reference to prior version:** (Part 5.7) New Requirement

**Change Rationale:** (Part 5.7)

*Minimizing the number of unsuccessful login attempts significantly reduces the risk of live password cracking attempts. This is a more effective control in live password attacks than password parameters.*

### Version History

| Version | Date     | Action  | Change Tracking |
|---------|----------|---|-----------------|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”   | 3/24/06         |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority. |                 |
| 3       | 12/16/09 | Updated version number from -2 to -3 Approved by the NERC Board of Trustees.  |                 |



Guidelines and Technical Basis

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|             |            |   |   |
|-------------|------------|---|---|
| 3           | 3/31/10    | Approved by FERC.   |   |
| 4           | 12/30/10   | Modified to add specific criteria for Critical Asset identification.        | Update  |
| 4           | 1/24/11    | Approved by the NERC Board of Trustees.                                     | Update  |
| 5           | 11/26/12   | Adopted by the NERC Board of Trustees.                                      | Modified to coordinate with other CIP standards and to revise format to use RBS Template.           |
| 5           | 11/22/13   | FERC Order issued approving CIP-007-5. (Order becomes effective on 2/3/14.) |   |
| <u>5(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>                                | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning
2. **Number:** CIP-008-5(X)
3. **Purpose:** To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**
    - 4.1.8 **Transmission Owner**

- 4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.
- 4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:
- 4.2.1.1** Each UFLS or UVLS System that:
- 4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
  - 4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
- 4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
- 4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
- 4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
- 4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**  
All BES Facilities.
- 4.2.3 Exemptions:** The following are exempt from Standard CIP-008-5(X):
- 4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
  - 4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
  - 4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
  - 4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.
  - 4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-008-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-008-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-008-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

## B. Requirements and Measures

- R1.** Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*.
- M1.** Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*.

| CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications |  |   |   |
|--|--|---|---|
| Part   | Applicable Systems   | Requirements  | Measures  |
| 1.1  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | One or more processes to identify, classify, and respond to Cyber Security Incidents.   | An example of evidence may include, but is not limited to, dated documentation of Cyber Security Incident response plan(s) that include the process to identify, classify, and respond to Cyber Security Incidents.   |
| 1.2  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | One or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident and notify the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), unless prohibited by law. Initial notification to the ES-ISAC, which may be only a preliminary notice, shall not exceed one hour from the determination of a Reportable Cyber Security Incident. | Examples of evidence may include, but are not limited to, dated documentation of Cyber Security Incident response plan(s) that provide guidance or thresholds for determining which Cyber Security Incidents are also Reportable Cyber Security Incidents and documentation of initial notices to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). |

| CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 1.3  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | The roles and responsibilities of Cyber Security Incident response groups or individuals. | An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that define roles and responsibilities (e.g., monitoring, reporting, initiating, documenting, etc.) of Cyber Security Incident response groups or individuals. |
| 1.4  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Incident handling procedures for Cyber Security Incidents.                                | An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).   |

- R2.** Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-Time Operations].
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*.

| CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing |  |   |   |
|--|--|---|---|
| Part   | Applicable Systems   | Requirements  | Measures  |
| 2.1  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Test each Cyber Security Incident response plan(s) at least once every 15 calendar months: <ul style="list-style-type: none"> <li>• By responding to an actual Reportable Cyber Security Incident;</li> <li>• With a paper drill or tabletop exercise of a Reportable Cyber Security Incident; or</li> <li>• With an operational exercise of a Reportable Cyber Security Incident.</li> </ul> | Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises. |



| CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 2.2  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Use the Cyber Security Incident response plan(s) under Requirement R1 when responding to a Reportable Cyber Security Incident or performing an exercise of a Reportable Cyber Security Incident. Document deviations from the plan(s) taken during the response to the incident or exercise. | Examples of evidence may include, but are not limited to, incident reports, logs, and notes that were kept during the incident response process, and follow-up documentation that describes deviations taken from the plan during the incident or exercise.                                 |
| 2.3  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Retain records related to Reportable Cyber Security Incidents.   | An example of evidence may include, but is not limited to, dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to Reportable Cyber Security Incidents. |

- R3.** Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].
- M3.** Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each Cyber Security Incident response plan according to the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident*.

| CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication |  |  |   |
|---|--|--|---|
| Part  | Applicable Systems   | Requirements   | Measures  |
| 3.1   | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | <p>No later than 90 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response:</p> <p>3.1.1. Document any lessons learned or document the absence of any lessons learned;</p> <p>3.1.2. Update the Cyber Security Incident response plan based on any documented lessons learned associated with the plan; and</p> <p>3.1.3. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates to the Cyber Security Incident response plan based on any documented lessons learned.</p> | <p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response or dated documentation stating there were no lessons learned;</li> <li>2. Dated and revised Cyber Security Incident response plan showing any changes based on the lessons learned; and</li> <li>3. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

| CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 3.2   | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | <p>No later than 60 calendar days after a change to the roles or responsibilities, Cyber Security Incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan:</p> <p>3.2.1. Update the Cyber Security Incident response plan(s); and</p> <p>3.2.2. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates.</p> | <p>An example of evidence may include, but is not limited to:</p> <ol style="list-style-type: none"> <li>1. Dated and revised Cyber Security Incident response plan with changes to the roles or responsibilities, responders or technology; and</li> <li>2. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon       | VRF   | Violation Severity Levels (CIP-008-5(X)) |              |  |   |
|-----|--------------------|-------|--|--------------|--|---|
|     |                    |       | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL  |
| R1  | Long Term Planning | Lower | N/A                                      | N/A          | <p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include the roles and responsibilities of Cyber Security Incident response groups or individuals. (1.3)</p> <p>OR</p> <p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include incident handling procedures for Cyber Security Incidents. (1.4)</p> | <p>The Responsible Entity has not developed a Cyber Security Incident response plan with one or more processes to identify, classify, and respond to Cyber Security Incidents. (1.1)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to identify Reportable Cyber Security Incidents. (1.2)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but did</p> |

| R #       | Time Horizon  | VRF          | Violation Severity Levels (CIP-008-5(X))  |   |   |   |
|-----------|---|--------------|---|---|---|---|
|           |   |              | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|           |   |              |   |   |   | not provide at least preliminary notification to ES-ISAC within one hour from identification of a Reportable Cyber Security Incident. (1.2)   |
| <b>R2</b> | <b>Operations Planning<br/>Real-time Operations</b> | <b>Lower</b> | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 15 calendar months, not exceeding 16 calendar months between tests of the plan. (2.1) | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan. (2.1) | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 17 calendar months, not exceeding 18 calendar months between tests of the plan. (2.1)<br><br>OR<br>The Responsible Entity did not document deviations, if any, from the plan during a test or when a Reportable Cyber Security Incident occurs. (2.2) | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 19 calendar months between tests of the plan. (2.1)<br><br>OR<br>The Responsible Entity did not retain relevant records related to Reportable Cyber Security Incidents. (2.3) |
| <b>R3</b> | <b>Operations Assessment</b>                        | <b>Lower</b> | The Responsible Entity has not notified each person or group with   | The Responsible Entity has not updated the  | The Responsible Entity has neither  | The Responsible Entity has neither  |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-008-5(X))  |   |   |  |
|-----|--------------|-----|---|---|---|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within greater than 90 but less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3) | Cyber Security Incident response plan based on any documented lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2)<br>OR<br>The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)<br>OR | documented lessons learned nor documented the absence of any lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)<br>OR<br>The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2)<br>OR<br>The Responsible Entity has not updated the | documented lessons learned nor documented the absence of any lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1) |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-008-5(X)) |  |  |            |
|-----|--------------|-----|--|--|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL |
|     |              |     |  | <p>The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> <li>• Cyber Security Incident response groups or individuals, or</li> <li>• Technology changes.</li> </ul> | <p>Cyber Security Incident response plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> <li>• Cyber Security Incident response groups or individuals, or</li> <li>• Technology changes.</li> </ul> |            |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

The following guidelines are available to assist in addressing the required components of a Cyber Security Incident response plan:

- Department of Homeland Security, Control Systems Security Program, *Developing an Industrial Control Systems Cyber Security Incident Response Capability*, 2009, online at [http://www.us-cert.gov/control\\_systems/practices/documents/final-RP\\_ics\\_cybersecurity\\_incident\\_response\\_100609.pdf](http://www.us-cert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf)
- National Institute of Standards and Technology, *Computer Security Incident Handling Guide*, Special Publication 800-61 revision 1, March 2008, online at <http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf>

For Part 1.2, a Reportable Cyber Security Incident is a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity. It is helpful to distinguish Reportable Cyber Security Incidents as one resulting in a necessary response action. A response action can fall into one of two categories: Necessary or elective. The distinguishing characteristic is whether or not action was taken in response to an event. Precautionary measures that are not in response to any persistent damage or effects may be designated as elective. All other response actions to avoid any persistent damage or adverse effects, which include the activation of redundant systems, should be designated as necessary.

The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.

### **Requirement R2:**

Requirement R2 ensures entities periodically test the Cyber Security Incident response plan. This includes the requirement in Part 2.2 to ensure the plan is actually used when testing. The testing requirements are specifically for *Reportable Cyber Security Incidents*.

Entities may use an actual response to a *Reportable Cyber Security Incident* as a substitute for exercising the plan annually. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or full operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, “A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. Table top exercises (TTX) can be used to assess plans, policies, and procedures.”

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, “[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and ‘boots on the ground’ response (e.g., firefighters decontaminating mock victims).”

In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for *Reportable Cyber Security Incidents*. There are several examples of specific types of evidence listed in the measure. Entities should refer to their handling procedures to determine the types of evidence to retain and how to transport and store the evidence. For further information in retaining incident records, refer to the NIST Guide to Integrating Forensic Techniques into Incident Response (SP800-86). The NIST guideline includes a section (Section 3.1.2) on acquiring data when performing forensics.

### **Requirement R3:**

This requirement ensures entities maintain Cyber Security Incident response plans. There are two requirement parts that trigger plan updates: (1) lessons learned from Part 3.1 and (2) organizational or technology changes from Part 3.2.

The documentation of lessons learned from Part 3.1 is associated with each Reportable Cyber Security Incident and involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the incident in recognition that complex incidents on complex systems can take a few days or weeks to complete response

activities. The process of conducting lessons learned can involve the response team discussing the incident to determine gaps or areas of improvement within the plan. Any documented deviations from the plan from Part 2.2 can serve as input to the lessons learned. It is possible to have a *Reportable Cyber Security Incident* without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the *Reportable Cyber Security Incident*.

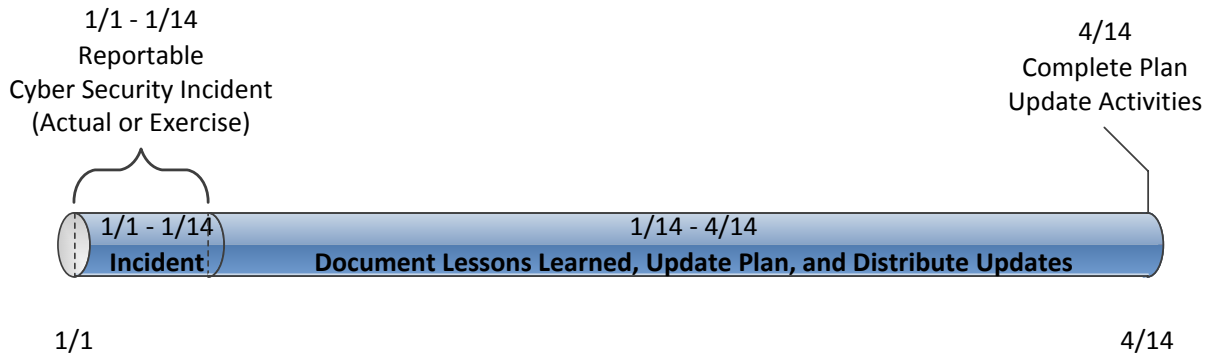


Figure 1: CIP-008-5(X) R3 Timeline for Reportable Cyber Security Incidents

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the incident and documenting the lessons learned as soon after the incident as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the incident response team.

The plan change requirement in Part 3.2 is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems or ticketing systems.

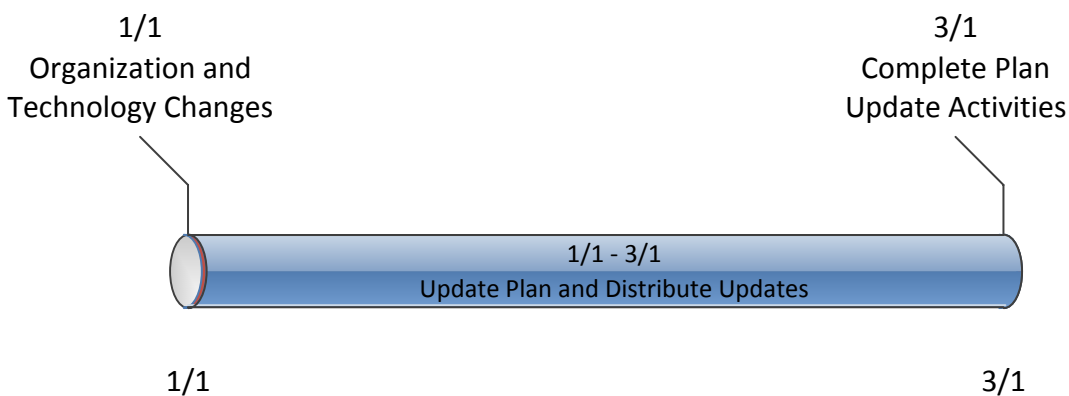


Figure 2: Timeline for Plan Changes in 3.2

## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned incident response capability is therefore necessary for rapidly detecting incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services. An enterprise or single incident response plan for all BES Cyber Systems may be used to meet the Requirement. An organization may have a common plan for multiple registered entities it owns.

**Summary of Changes:** Wording changes have been incorporated based primarily on industry feedback to more specifically describe required actions.

**Reference to prior version:** (Part 1.1) CIP-008, R1.1

**Change Description and Justification:** (Part 1.1)

*“Characterize” has been changed to “identify” for clarity. “Response actions” has been changed to “respond to” for clarity.*

**Reference to prior version:** (Part 1.2) CIP-008, R1.1

**Change Description and Justification:** (Part 1.2)

*Addresses the reporting requirements from previous versions of CIP-008. This requirement part only obligates entities to have a process for determining Reportable Cyber Security Incidents. Also addresses the directive in FERC Order No. 706, paragraphs 673 and 676 to report within one hour (at least preliminarily).*

**Reference to prior version:** (Part 1.3) CIP-008, R1.2

**Change Description and Justification:** (Part 1.3)

*Replaced incident response teams with incident response “groups or individuals” to avoid the interpretation that roles and responsibilities sections must reference specific teams.*

**Reference to prior version:** (Part 1.4) CIP-008, R1.2

**Change Description and Justification:** (Part 1.4)

*Conforming change to reference new defined term Cyber Security Incidents.*

**Rationale for R2:**

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. This requirement ensures implementation of the response plans. Requirement Part 2.3 ensures the retention of incident documentation for post event analysis.

This requirement obligates entities to follow the Cyber Security Incident response plan when an incident occurs or when testing, but does not restrict entities from taking needed deviations from the plan. It ensures the plan represents the actual response and does not exist for documentation only. If a plan is written at a high enough level, then every action during the response should not be subject to scrutiny. The plan will likely allow for the appropriate variance in tactical decisions made by incident responders. Deviations from the plan can be documented during the incident response or afterward as part of the review.

**Summary of Changes:** Added testing requirements to verify the Responsible Entity’s response plan’s effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.

**Reference to prior version:** (Part 2.1) CIP-008, R1.6

**Change Description and Justification:** (Part 2.1)

*Minor wording changes; essentially unchanged.*

**Reference to prior version:** (Part 2.2) CIP-008, R1.6

**Change Description and Justification:** (Part 2.2)

*Allows deviation from plan(s) during actual events or testing if deviations are recorded for review.*

**Reference to prior version:** (Part 2.3) CIP-008, R2

**Change Description and Justification:** (Part 2.3)

*Removed references to the retention period because the Standard addresses data retention in the Compliance Section.*

**Rationale for R3:**

Conduct sufficient reviews, updates and communications to verify the Responsible Entity’s response plan’s effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System. A separate plan is not required for those requirement parts of the table applicable to High or Medium Impact BES Cyber Systems. If an entity has a single Cyber Security Incident response plan and High or Medium Impact BES Cyber Systems, then the additional requirements would apply to the single plan.

**Summary of Changes:** Changes here address the FERC Order 706, Paragraph 686, which includes a directive to perform after-action review for tests or actual incidents and update the

plan based on lessons learned. Additional changes include specification of what it means to review the plan and specification of changes that would require an update to the plan.

**Reference to prior version:** (Part 3.1) CIP-008, R1.5

**Change Description and Justification:** (Part 3.1)

*Addresses FERC Order 706, Paragraph 686 to document test or actual incidents and lessons learned.*

**Reference to prior version:** (Part 3.2) CIP-008, R1.4

**Change Description and Justification:** (Part 3.2)

*Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the changes that would require an update.*

### Version History

| Version | Date     | Action  | Change Tracking |
|---------|----------|---|-----------------|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”   | 3/24/06         |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority. |                 |
| 3       |          | Updated version number from -2 to -3<br>In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.  |                 |
| 3       | 12/16/09 | Approved by the NERC Board of Trustees.   | Update          |
| 3       | 3/31/10  | Approved by FERC.   |                 |



## Guidelines and Technical Basis

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|      |          |   |  |
|------|----------|---|--|
| 4    | 12/30/10 | Modified to add specific criteria for Critical Asset identification.        | Update   |
| 4    | 1/24/11  | Approved by the NERC Board of Trustees.                                     | Update   |
| 5    | 11/26/12 | Adopted by the NERC Board of Trustees.                                      | Modified to coordinate with other CIP standards and to revise format to use RBS Template.    |
| 5    | 11/22/13 | FERC Order issued approving CIP-008-5. (Order becomes effective on 2/3/14.) |  |
| 5(X) | TBD      | Adopted by the NERC Board of Trustees                                       | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning
2. **Number:** CIP-008-5(X)
3. **Purpose:** To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**

#### 4.1.8 Transmission Owner

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-008-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-008-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-008-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-008-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

## B. Requirements and Measures

- R1.** Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*.  
[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].
- M1.** Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*.

| CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications |  |   |   |
|--|--|---|---|
| Part   | Applicable Systems   | Requirements  | Measures  |
| 1.1  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | One or more processes to identify, classify, and respond to Cyber Security Incidents.   | An example of evidence may include, but is not limited to, dated documentation of Cyber Security Incident response plan(s) that include the process to identify, classify, and respond to Cyber Security Incidents.   |
| 1.2  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | One or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident and notify the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), unless prohibited by law. Initial notification to the ES-ISAC, which may be only a preliminary notice, shall not exceed one hour from the determination of a Reportable Cyber Security Incident. | Examples of evidence may include, but are not limited to, dated documentation of Cyber Security Incident response plan(s) that provide guidance or thresholds for determining which Cyber Security Incidents are also Reportable Cyber Security Incidents and documentation of initial notices to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). |

| CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 1.3  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | The roles and responsibilities of Cyber Security Incident response groups or individuals. | An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that define roles and responsibilities (e.g., monitoring, reporting, initiating, documenting, etc.) of Cyber Security Incident response groups or individuals. |
| 1.4  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Incident handling procedures for Cyber Security Incidents.                                | An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).   |

- R2.** Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-Time Operations].
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*.

| CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing |  |   |   |
|--|--|---|---|
| Part   | Applicable Systems   | Requirements  | Measures  |
| 2.1  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Test each Cyber Security Incident response plan(s) at least once every 15 calendar months: <ul style="list-style-type: none"> <li>• By responding to an actual Reportable Cyber Security Incident;</li> <li>• With a paper drill or tabletop exercise of a Reportable Cyber Security Incident; or</li> <li>• With an operational exercise of a Reportable Cyber Security Incident.</li> </ul> | Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises. |



| CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 2.2  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Use the Cyber Security Incident response plan(s) under Requirement R1 when responding to a Reportable Cyber Security Incident or performing an exercise of a Reportable Cyber Security Incident. Document deviations from the plan(s) taken during the response to the incident or exercise. | Examples of evidence may include, but are not limited to, incident reports, logs, and notes that were kept during the incident response process, and follow-up documentation that describes deviations taken from the plan during the incident or exercise.                                 |
| 2.3  | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | Retain records related to Reportable Cyber Security Incidents.   | An example of evidence may include, but is not limited to, dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to Reportable Cyber Security Incidents. |

- R3.** Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].
- M3.** Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each Cyber Security Incident response plan according to the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident*.

| CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication |  |  |   |
|---|--|--|---|
| Part  | Applicable Systems   | Requirements   | Measures  |
| 3.1   | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | <p>No later than 90 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response:</p> <p>3.1.1. Document any lessons learned or document the absence of any lessons learned;</p> <p>3.1.2. Update the Cyber Security Incident response plan based on any documented lessons learned associated with the plan; and</p> <p>3.1.3. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates to the Cyber Security Incident response plan based on any documented lessons learned.</p> | <p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response or dated documentation stating there were no lessons learned;</li> <li>2. Dated and revised Cyber Security Incident response plan showing any changes based on the lessons learned; and</li> <li>3. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

| CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication |  |   |   |
|---|--|---|---|
| Part  | Applicable Systems   | Requirements  | Measures  |
| 3.2   | High Impact BES Cyber Systems<br>Medium Impact BES Cyber Systems | <p>No later than 60 calendar days after a change to the roles or responsibilities, Cyber Security Incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan:</p> <p>3.2.1. Update the Cyber Security Incident response plan(s); and</p> <p>3.2.2. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates.</p> | <p>An example of evidence may include, but is not limited to:</p> <ol style="list-style-type: none"> <li>1. Dated and revised Cyber Security Incident response plan with changes to the roles or responsibilities, responders or technology; and</li> <li>2. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon       | VRF   | Violation Severity Levels (CIP-008-5(X)) |              |  |   |
|-----|--------------------|-------|--|--------------|--|---|
|     |                    |       | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL  |
| R1  | Long Term Planning | Lower | N/A                                      | N/A          | <p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include the roles and responsibilities of Cyber Security Incident response groups or individuals. (1.3)</p> <p>OR</p> <p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include incident handling procedures for Cyber Security Incidents. (1.4)</p> | <p>The Responsible Entity has not developed a Cyber Security Incident response plan with one or more processes to identify, classify, and respond to Cyber Security Incidents. (1.1)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to identify Reportable Cyber Security Incidents. (1.2)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but did</p> |

| R #       | Time Horizon  | VRF          | Violation Severity Levels (CIP-008-5(X))  |   |   |   |
|-----------|---|--------------|---|---|---|---|
|           |   |              | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|           |   |              |   |   |   | not provide at least preliminary notification to ES-ISAC within one hour from identification of a Reportable Cyber Security Incident. (1.2)   |
| <b>R2</b> | <b>Operations Planning<br/>Real-time Operations</b> | <b>Lower</b> | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 15 calendar months, not exceeding 16 calendar months between tests of the plan. (2.1) | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan. (2.1) | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 17 calendar months, not exceeding 18 calendar months between tests of the plan. (2.1)<br><br>OR<br>The Responsible Entity did not document deviations, if any, from the plan during a test or when a Reportable Cyber Security Incident occurs. (2.2) | The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 19 calendar months between tests of the plan. (2.1)<br><br>OR<br>The Responsible Entity did not retain relevant records related to Reportable Cyber Security Incidents. (2.3) |
| <b>R3</b> | <b>Operations Assessment</b>                        | <b>Lower</b> | The Responsible Entity has not notified each person or group with   | The Responsible Entity has not updated the  | The Responsible Entity has neither  | The Responsible Entity has neither  |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-008-5(X))   |  |  |   |
|-----|--------------|-----|--|--|--|---|
|     |              |     | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|     |              |     | <p>a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within greater than 90 but less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)</p> | <p>Cyber Security Incident response plan based on any documented lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)</p> <p>OR</p> | <p>documented lessons learned nor documented the absence of any lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)</p> <p>OR</p> <p>The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not updated the</p> | <p>documented lessons learned nor documented the absence of any lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-008-5(X)) |  |  |            |
|-----|--------------|-----|--|--|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL |
|     |              |     |  | <p>The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> <li>• Cyber Security Incident response groups or individuals, or</li> <li>• Technology changes.</li> </ul> | <p>Cyber Security Incident response plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> <li>• Cyber Security Incident response groups or individuals, or</li> <li>• Technology changes.</li> </ul> |            |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

The following guidelines are available to assist in addressing the required components of a Cyber Security Incident response plan:

- Department of Homeland Security, Control Systems Security Program, *Developing an Industrial Control Systems Cyber Security Incident Response Capability*, 2009, online at [http://www.us-cert.gov/control\\_systems/practices/documents/final-RP\\_ics\\_cybersecurity\\_incident\\_response\\_100609.pdf](http://www.us-cert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf)
- National Institute of Standards and Technology, *Computer Security Incident Handling Guide*, Special Publication 800-61 revision 1, March 2008, online at <http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf>

For Part 1.2, a Reportable Cyber Security Incident is a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity. It is helpful to distinguish Reportable Cyber Security Incidents as one resulting in a necessary response action. A response action can fall into one of two categories: Necessary or elective. The distinguishing characteristic is whether or not action was taken in response to an event. Precautionary measures that are not in response to any persistent damage or effects may be designated as elective. All other response actions to avoid any persistent damage or adverse effects, which include the activation of redundant systems, should be designated as necessary.

The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.

### **Requirement R2:**

Requirement R2 ensures entities periodically test the Cyber Security Incident response plan. This includes the requirement in Part 2.2 to ensure the plan is actually used when testing. The testing requirements are specifically for *Reportable Cyber Security Incidents*.

Entities may use an actual response to a *Reportable Cyber Security Incident* as a substitute for exercising the plan annually. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or full operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, “A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. Table top exercises (TTX) can be used to assess plans, policies, and procedures.”

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, “[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and ‘boots on the ground’ response (e.g., firefighters decontaminating mock victims).”

In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for *Reportable Cyber Security Incidents*. There are several examples of specific types of evidence listed in the measure. Entities should refer to their handling procedures to determine the types of evidence to retain and how to transport and store the evidence. For further information in retaining incident records, refer to the NIST Guide to Integrating Forensic Techniques into Incident Response (SP800-86). The NIST guideline includes a section (Section 3.1.2) on acquiring data when performing forensics.

### **Requirement R3:**

This requirement ensures entities maintain Cyber Security Incident response plans. There are two requirement parts that trigger plan updates: (1) lessons learned from Part 3.1 and (2) organizational or technology changes from Part 3.2.

The documentation of lessons learned from Part 3.1 is associated with each Reportable Cyber Security Incident and involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the incident in recognition that complex incidents on complex systems can take a few days or weeks to complete response

activities. The process of conducting lessons learned can involve the response team discussing the incident to determine gaps or areas of improvement within the plan. Any documented deviations from the plan from Part 2.2 can serve as input to the lessons learned. It is possible to have a *Reportable Cyber Security Incident* without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the *Reportable Cyber Security Incident*.

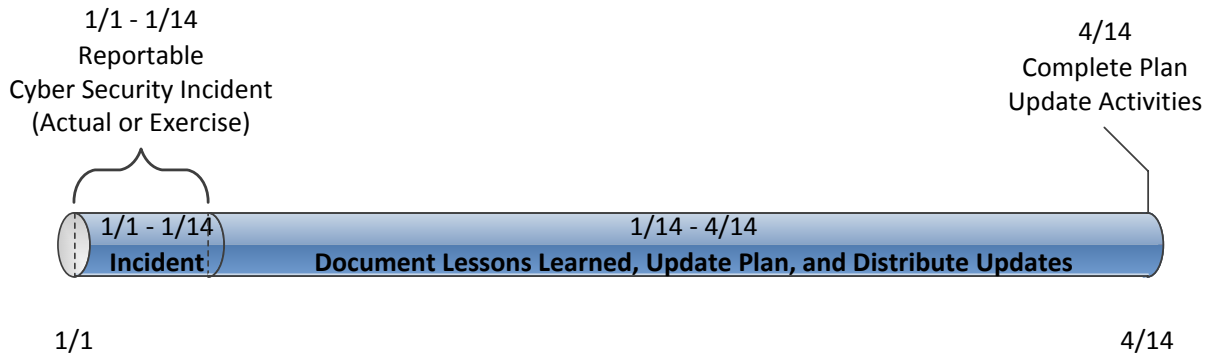


Figure 1: CIP-008-5(X) R3 Timeline for Reportable Cyber Security Incidents

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the incident and documenting the lessons learned as soon after the incident as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the incident response team.

The plan change requirement in Part 3.2 is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems or ticketing systems.

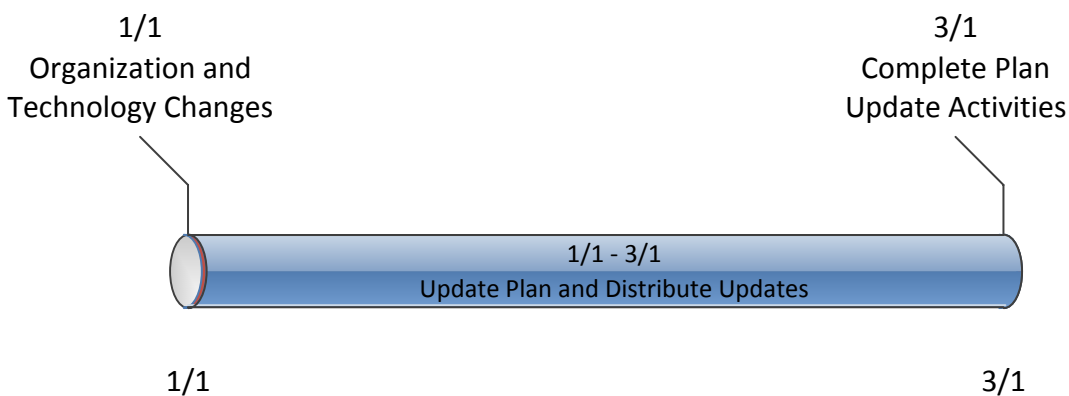


Figure 2: Timeline for Plan Changes in 3.2

## **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

### **Rationale for R1:**

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned incident response capability is therefore necessary for rapidly detecting incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services. An enterprise or single incident response plan for all BES Cyber Systems may be used to meet the Requirement. An organization may have a common plan for multiple registered entities it owns.

**Summary of Changes:** Wording changes have been incorporated based primarily on industry feedback to more specifically describe required actions.

**Reference to prior version:** (Part 1.1) CIP-008, R1.1

**Change Description and Justification:** (Part 1.1)

*“Characterize” has been changed to “identify” for clarity. “Response actions” has been changed to “respond to” for clarity.*

**Reference to prior version:** (Part 1.2) CIP-008, R1.1

**Change Description and Justification:** (Part 1.2)

*Addresses the reporting requirements from previous versions of CIP-008. This requirement part only obligates entities to have a process for determining Reportable Cyber Security Incidents. Also addresses the directive in FERC Order No. 706, paragraphs 673 and 676 to report within one hour (at least preliminarily).*

**Reference to prior version:** (Part 1.3) CIP-008, R1.2

**Change Description and Justification:** (Part 1.3)

*Replaced incident response teams with incident response “groups or individuals” to avoid the interpretation that roles and responsibilities sections must reference specific teams.*

**Reference to prior version:** (Part 1.4) CIP-008, R1.2

**Change Description and Justification:** (Part 1.4)

*Conforming change to reference new defined term Cyber Security Incidents.*

**Rationale for R2:**

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. This requirement ensures implementation of the response plans. Requirement Part 2.3 ensures the retention of incident documentation for post event analysis.

This requirement obligates entities to follow the Cyber Security Incident response plan when an incident occurs or when testing, but does not restrict entities from taking needed deviations from the plan. It ensures the plan represents the actual response and does not exist for documentation only. If a plan is written at a high enough level, then every action during the response should not be subject to scrutiny. The plan will likely allow for the appropriate variance in tactical decisions made by incident responders. Deviations from the plan can be documented during the incident response or afterward as part of the review.

**Summary of Changes:** Added testing requirements to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.

**Reference to prior version:** (Part 2.1) CIP-008, R1.6

**Change Description and Justification:** (Part 2.1)

*Minor wording changes; essentially unchanged.*

**Reference to prior version:** (Part 2.2) CIP-008, R1.6

**Change Description and Justification:** (Part 2.2)

*Allows deviation from plan(s) during actual events or testing if deviations are recorded for review.*

**Reference to prior version:** (Part 2.3) CIP-008, R2

**Change Description and Justification:** (Part 2.3)

*Removed references to the retention period because the Standard addresses data retention in the Compliance Section.*

**Rationale for R3:**

Conduct sufficient reviews, updates and communications to verify the Responsible Entity's response plan's effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System. A separate plan is not required for those requirement parts of the table applicable to High or Medium Impact BES Cyber Systems. If an entity has a single Cyber Security Incident response plan and High or Medium Impact BES Cyber Systems, then the additional requirements would apply to the single plan.

**Summary of Changes:** Changes here address the FERC Order 706, Paragraph 686, which includes a directive to perform after-action review for tests or actual incidents and update the

plan based on lessons learned. Additional changes include specification of what it means to review the plan and specification of changes that would require an update to the plan.

**Reference to prior version:** (Part 3.1) CIP-008, R1.5

**Change Description and Justification:** (Part 3.1)

*Addresses FERC Order 706, Paragraph 686 to document test or actual incidents and lessons learned.*

**Reference to prior version:** (Part 3.2) CIP-008, R1.4

**Change Description and Justification:** (Part 3.2)

*Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the changes that would require an update.*

**Version History**

| Version | Date     | Action  | Change Tracking |
|---------|----------|---|-----------------|
| 1       | 1/16/06  | R3.2 — Change “Control Center” to “control center.”   | 3/24/06         |
| 2       | 9/30/09  | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority. |                 |
| 3       |          | Updated version number from -2 to -3<br>In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.  |                 |
| 3       | 12/16/09 | Approved by the NERC Board of Trustees.   | Update          |
| 3       | 3/31/10  | Approved by FERC.   |                 |



Guidelines and Technical Basis

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|             |            |   |   |
|-------------|------------|---|---|
| 4           | 12/30/10   | Modified to add specific criteria for Critical Asset identification.        | Update  |
| 4           | 1/24/11    | Approved by the NERC Board of Trustees.                                     | Update  |
| 5           | 11/26/12   | Adopted by the NERC Board of Trustees.                                      | Modified to coordinate with other CIP standards and to revise format to use RBS Template.           |
| 5           | 11/22/13   | FERC Order issued approving CIP-008-5. (Order becomes effective on 2/3/14.) |   |
| <u>5(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>                                | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** Cyber Security — Recovery Plans for BES Cyber Systems
2. **Number:** CIP-009-5(X)
3. **Purpose:** To recover reliability functions performed by BES Cyber Systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**
    - 4.1.7 **Transmission Operator**

#### **4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-009-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-009-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-009-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-009-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding

paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to BES Cyber Systems located at a Control Center and categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples include, but are not limited to firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

**B. Requirements and Measures**

- R1.** Each Responsible Entity shall have one or more documented recovery plans that collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning].
- M1.** Evidence must include the documented recovery plan(s) that collectively include the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*.

| CIP-009-5(X) Table R1 – Recovery Plan Specifications |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements                                       | Measures  |
| 1.1  | High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol><br>Medium Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | Conditions for activation of the recovery plan(s). | An example of evidence may include, but is not limited to, one or more plans that include language identifying conditions for activation of the recovery plan(s). |

| CIP-009-5(X) Table R1 – Recovery Plan Specifications |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirements  | Measures   |
| 1.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | Roles and responsibilities of responders.   | An example of evidence may include, but is not limited to, one or more recovery plans that include language identifying the roles and responsibilities of responders.                        |
| 1.3  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | One or more processes for the backup and storage of information required to recover BES Cyber System functionality. | An example of evidence may include, but is not limited to, documentation of specific processes for the backup and storage of information required to recover BES Cyber System functionality. |



| CIP-009-5(X) Table R1 – Recovery Plan Specifications |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 1.4  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>One or more processes to verify the successful completion of the backup processes in Part 1.3 and to address any backup failures.</p>  | <p>An example of evidence may include, but is not limited to, logs, workflow or other documentation confirming that the backup process completed successfully and backup failures, if any, were addressed.</p> |
| 1.5  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol>                    | <p>One or more processes to preserve data, per Cyber Asset capability, for determining the cause of a Cyber Security Incident that triggers activation of the recovery plan(s). Data preservation should not impede or restrict recovery.</p> | <p>An example of evidence may include, but is not limited to, procedures to preserve data, such as preserving a corrupted drive or making a data mirror of the system before proceeding with recovery.</p>     |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, its documented recovery plan(s) to collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-time Operations.]
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*.

| CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 2.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Test each of the recovery plans referenced in Requirement R1 at least once every 15 calendar months:</p> <ul style="list-style-type: none"> <li>• By recovering from an actual incident;</li> <li>• With a paper drill or tabletop exercise; or</li> <li>• With an operational exercise.</li> </ul> | <p>An example of evidence may include, but is not limited to, dated evidence of a test (by recovering from an actual incident, with a paper drill or tabletop exercise, or with an operational exercise) of the recovery plan at least once every 15 calendar months. For the paper drill or full operational exercise, evidence may include meeting notices, minutes, or other records of exercise findings.</p> |

| CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 2.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Test a representative sample of information used to recover BES Cyber System functionality at least once every 15 calendar months to ensure that the information is useable and is compatible with current configurations.</p> <p>An actual recovery that incorporates the information used to recover BES Cyber System functionality substitutes for this test.</p> | <p>An example of evidence may include, but is not limited to, operational logs or test results with criteria for testing the usability (e.g. sample tape load, browsing tape contents) and compatibility with current system configurations (e.g. manual or automated comparison checkpoints between backup media contents and current configuration).</p>   |
| 2.3  | High Impact BES Cyber Systems  | <p>Test each of the recovery plans referenced in Requirement R1 at least once every 36 calendar months through an operational exercise of the recovery plans in an environment representative of the production environment.</p> <p>An actual recovery response may substitute for an operational exercise.</p>   | <p>Examples of evidence may include, but are not limited to, dated documentation of:</p> <ul style="list-style-type: none"> <li>• An operational exercise at least once every 36 calendar months between exercises, that demonstrates recovery in a representative environment; or</li> <li>• An actual recovery response that occurred within the 36 calendar month timeframe that exercised the recovery plans.</li> </ul> |

**R3.** Each Responsible Entity shall maintain each of its recovery plans in accordance with each of the applicable requirement parts in CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].

**M3.** Acceptable evidence includes, but is not limited to, each of the applicable requirement parts in CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication.

| CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 3.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>No later than 90 calendar days after completion of a recovery plan test or actual recovery:</p> <ol style="list-style-type: none"> <li>3.1.1. Document any lessons learned associated with a recovery plan test or actual recovery or document the absence of any lessons learned;</li> <li>3.1.2. Update the recovery plan based on any documented lessons learned associated with the plan; and</li> <li>3.1.3. Notify each person or group with a defined role in the recovery plan of the updates to the recovery plan based on any documented lessons learned.</li> </ol> | <p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated documentation of identified deficiencies or lessons learned for each recovery plan test or actual incident recovery or dated documentation stating there were no lessons learned;</li> <li>2. Dated and revised recovery plan showing any changes based on the lessons learned; and</li> <li>3. Evidence of plan update distribution including, but not limited to:                             <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

| CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication |  |  |  |
|--|--|--|--|
| Part   | Applicable Systems   | Requirements   | Measures   |
| 3.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>No later than 60 calendar days after a change to the roles or responsibilities, responders, or technology that the Responsible Entity determines would impact the ability to execute the recovery plan:</p> <ol style="list-style-type: none"> <li>3.2.1. Update the recovery plan; and</li> <li>3.2.2. Notify each person or group with a defined role in the recovery plan of the updates.</li> </ol> | <p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated and revised recovery plan with changes to the roles or responsibilities, responders, or technology; and</li> <li>2. Evidence of plan update distribution including, but not limited to:                             <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon       | VRF    | Violation Severity Levels (CIP-009-5(X)) |  |  |   |
|-----|--------------------|--------|--|--|--|---|
|     |                    |        | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL  |
| R1  | Long-term Planning | Medium | N/A                                      | The Responsible Entity has developed recovery plan(s), but the plan(s) do not address one of the requirements included in Parts 1.2 through 1.5. | The Responsible Entity has developed recovery plan(s), but the plan(s) do not address two of the requirements included in Parts 1.2 through 1.5. | The Responsible Entity has not created recovery plan(s) for BES Cyber Systems.<br><br>OR<br>The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address the conditions for activation in Part 1.1.<br><br>OR<br>The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address three or more of the requirements in Parts 1.2 through 1.5. |

| R #       | Time Horizon  | VRF          | Violation Severity Levels (CIP-009-5(X))   |  |  |   |
|-----------|---|--------------|--|--|--|---|
|           |   |              | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
| <b>R2</b> | <b>Operations Planning<br/>Real-time Operations</b> | <b>Lower</b> | <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 15 calendar months, not exceeding 16 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 15 calendar months, not exceeding 16 calendar months between tests, and</p> | <p>The Responsible Entity has not tested the recovery plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 16 calendar months, not exceeding 17 calendar months between tests, and when tested, any</p> | <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 17 calendar months, not exceeding 18 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 17 calendar months, not exceeding 18 calendar months between tests, and</p> | <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 18 calendar months between tests of the plan. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 and identified deficiencies, but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 but did not identify, assess, or correct the deficiencies. (2.1)</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X))  |  |   |   |
|-----|--------------|-----|---|--|---|---|
|     |              |     | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL  |
|     |              |     | <p>when tested, any deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 36 calendar months, not exceeding 37 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p> | <p>deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 37 calendar months, not exceeding 38 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p> | <p>when tested, any deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 38 calendar months, not exceeding 39 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p> | <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 18 calendar months between tests. (2.2)</p> <p>OR</p> <p>The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 and identified deficiencies, but did not assess or correct the deficiencies. (2.2)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | <p>OR</p> <p>The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.3 within 39 calendar months between tests of the plan. (2.3)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part</p> |

| R #       | Time Horizon                 | VRF          | Violation Severity Levels (CIP-009-5(X))   |  |  |  |
|-----------|------------------------------|--------------|--|--|--|--|
|           |                              |              | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|           |                              |              |  |  |  | 2.3 and identified deficiencies, but did not assess or correct the deficiencies. (2.3)<br><br>OR<br><br>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.3 but did not identify, assess, or correct the deficiencies. (2.3) |
| <b>R3</b> | <b>Operations Assessment</b> | <b>Lower</b> | The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 90 and less than 210 calendar days of the update being completed. (3.1.3) | The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.2)<br><br>OR | The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.1) | The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 210 calendar days of each recovery plan test or actual recovery. (3.1.1)  |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X)) |  |   |            |
|-----|--------------|-----|--|--|---|------------|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL  | Severe VSL |
|     |              |     |  | <p>The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 120 calendar days of the update being completed. (3.1.3)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> <li>• Responders, or</li> </ul> | <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 120 calendar days of each recovery plan test or actual recovery. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> </ul> |            |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X)) |   |  |            |
|-----|--------------|-----|--|---|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL  | High VSL   | Severe VSL |
|     |              |     |  | <ul style="list-style-type: none"> <li>• Technology changes.</li> </ul> | <ul style="list-style-type: none"> <li>• Responders, or Technology changes.</li> </ul> |            |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

The following guidelines are available to assist in addressing the required components of a recovery plan:

- NERC, Security Guideline for the Electricity Sector: Continuity of Business Processes and Operations Operational Functions, September 2011, online at <http://www.nerc.com/docs/cip/sgwg/Continuity%20of%20Business%20and%20Operational%20Functions%20FINAL%20102511.pdf>
- National Institute of Standards and Technology, Contingency Planning Guide for Federal Information Systems, Special Publication 800-34 revision 1, May 2010, online at [http://csrc.nist.gov/publications/nistpubs/800-34-rev1/sp800-34-rev1\\_errata-Nov11-2010.pdf](http://csrc.nist.gov/publications/nistpubs/800-34-rev1/sp800-34-rev1_errata-Nov11-2010.pdf)

The term recovery plan is used throughout this Standard to refer to a documented set of instructions and resources needed to recover reliability functions performed by BES Cyber Systems. The recovery plan may exist as part of a larger business continuity or disaster recovery plan, but the term does not imply any additional obligations associated with those disciplines outside of the Requirements.

A documented recovery plan may not be necessary for each applicable BES Cyber System. For example, the short-term recovery plan for a BES Cyber System in a specific substation may be

managed on a daily basis by advanced power system applications such as state estimation, contingency and remedial action, and outage scheduling. One recovery plan for BES Cyber Systems should suffice for several similar facilities such as those found in substations or power plants' facilities.

For Part 1.1, the conditions for activation of the recovery plan should consider viable threats to the BES Cyber System such as natural disasters, computing equipment failures, computing environment failures, and Cyber Security Incidents. A business impact analysis for the BES Cyber System may be useful in determining these conditions.

For Part 1.2, entities should identify the individuals required for responding to a recovery operation of the applicable BES Cyber System.

For Part 1.3, entities should consider the following types of information to recover BES Cyber System functionality:

1. Installation files and media;
2. Current backup tapes and any additional documented configuration settings;
3. Documented build or restoration procedures; and
4. Cross site replication storage.

For Part 1.4, the processes to verify the successful completion of backup processes should include checking for: (1) usability of backup media, (2) logs or inspection showing that information from current, production system could be read, and (3) logs or inspection showing that information was written to the backup media. Test restorations are not required for this Requirement Part. The following backup scenarios provide examples of effective processes to verify successful completion and detect any backup failures:

- Periodic (e.g. daily or weekly) backup process – Review generated logs or job status reports and set up notifications for backup failures.
- Non-periodic backup process– If a single backup is provided during the commissioning of the system, then only the initial and periodic (every 15 months) testing must be done. Additional testing should be done as necessary and can be a part of the configuration change management program.
- Data mirroring – Configure alerts on the failure of data transfer for an amount of time specified by the entity (e.g. 15 minutes) in which the information on the mirrored disk may no longer be useful for recovery.
- Manual configuration information – Inspect the information used for recovery prior to storing initially and periodically (every 15 months). Additional inspection should be done as necessary and can be a part of the configuration change management program.

The plan must also include processes to address backup failures. These processes should specify the response to failure notifications or other forms of identification.

For Part 1.5, the recovery plan must include considerations for preservation of data to determine the cause of a Cyber Security Incident. Because it is not always possible to initially



know if a Cyber Security Incident caused the recovery activation, the data preservation procedures should be followed until such point a Cyber Security Incident can be ruled out. CIP-008 addresses the retention of data associated with a Cyber Security Incident.

### **Requirement R2:**

A Responsible Entity must exercise each BES Cyber System recovery plan every 15 months. However, this does not necessarily mean that the entity must test each plan individually. BES Cyber Systems that are numerous and distributed, such as those found at substations, may not require an individual recovery plan and the associated redundant facilities since reengineering and reconstruction may be the generic response to a severe event. Conversely, there is typically one control center per bulk transmission service area that requires a redundant or backup facility. Because of these differences, the recovery plans associated with control centers differ a great deal from those associated with power plants and substations.

A recovery plan test does not necessarily cover all aspects of a recovery plan and failure scenarios, but the test should be sufficient to ensure the plan is up to date and at least one restoration process of the applicable cyber systems is covered.

Entities may use an actual recovery as a substitute for exercising the plan every 15 months. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, "A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. [Table top exercises (TTX)] can be used to assess plans, policies, and procedures."

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, "[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and 'boots on the ground' response (e.g., firefighters decontaminating mock victims)."

For Part 2.2, entities should refer to the backup and storage of information required to recover BES Cyber System functionality in Requirement Part 1.3. This provides additional assurance that the information will actually recover the BES Cyber System as necessary. For most complex computing equipment, a full test of the information is not feasible. Entities should determine the representative sample of information that provides assurance in the processes for Requirement Part 1.3. The test must include steps for ensuring the information is useable and current. For backup media, this can include testing a representative sample to make sure the information can be loaded, and checking the content to make sure the information reflects the current configuration of the applicable Cyber Assets.

### **Requirement R3:**

This requirement ensures entities maintain recovery plans. There are two requirement parts that trigger plan updates: (1) lessons learned and (2) organizational or technology changes.

The documentation of lessons learned is associated with each recovery activation, and it involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the recovery operation in recognition that complex recovery activities can take a few days or weeks to complete. The process of conducting lessons learned can involve the recovery team discussing the incident to determine gaps or areas of improvement within the plan. It is possible to have a recovery activation without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the recovery activation.

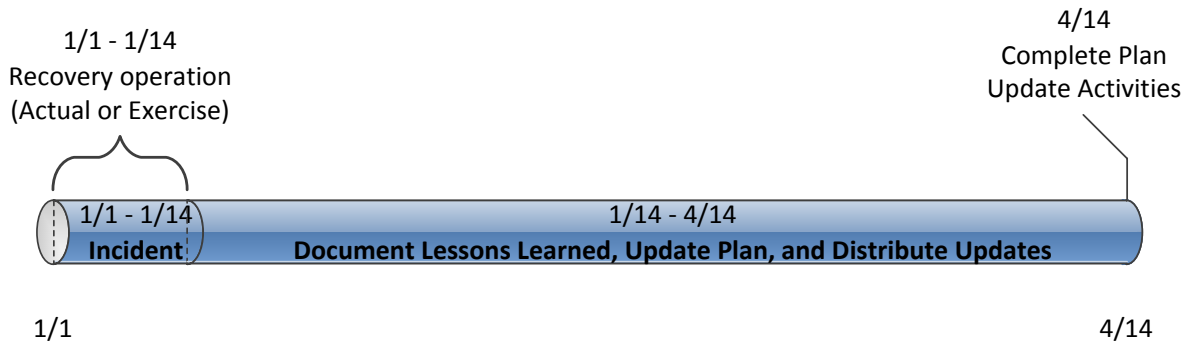


Figure 1: CIP-009-5(X) R3 Timeline

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the recovery and documenting the lessons learned as soon after the recovery activation as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the recovery team.

The plan change requirement is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems, or ticketing systems.

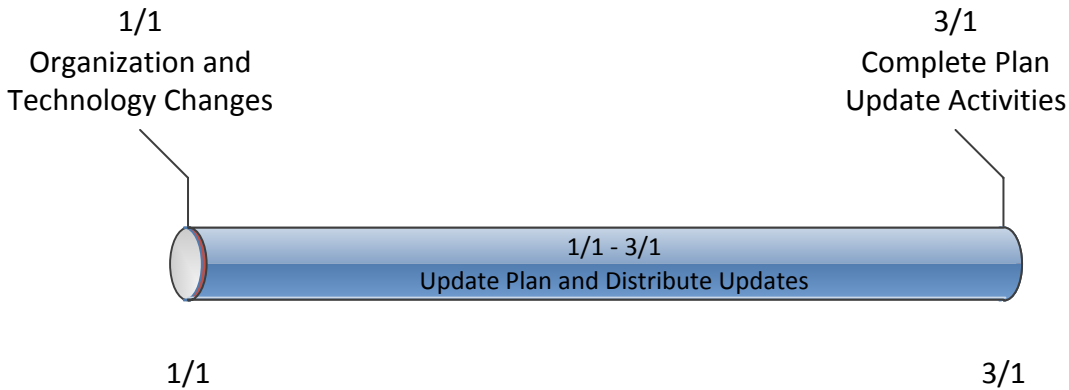


Figure 2: Timeline for Plan Changes in 3.2

When notifying individuals of response plan changes, entities should keep in mind that recovery plans may be considered BES Cyber System Information, and they should take the appropriate measures to prevent unauthorized disclosure of recovery plan information. For example, the recovery plan itself, or other sensitive information about the recovery plan, should be redacted from Email or other unencrypted transmission.

**Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

**Rationale for R1:**

Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned recovery capability is, therefore, necessary for rapidly recovering from incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services so that planned and consistent recovery action to restore BES Cyber System functionality occurs.

**Summary of Changes:** Added provisions to protect data that would be useful in the investigation of an event that results in the need for a Cyber System recovery plan to be utilized.

**Reference to prior version:** (Part 1.1) CIP-009, R1.1

**Change Description and Justification:** (Part 1.1)

*Minor wording changes; essentially unchanged.*

**Reference to prior version:** (Part 1.2) CIP-009, R1.2

**Change Description and Justification:** (Part 1.2)

*Minor wording changes; essentially unchanged.*

**Reference to prior version:** (Part 1.3) CIP-009, R4

**Change Description and Justification:** (Part 1.3)

*Addresses FERC Order Paragraph 739 and 748. The modified wording was abstracted from Paragraph 744.*

**Reference to prior version:** (Part 1.4) New Requirement

**Change Description and Justification:** (Part 1.4)

*Addresses FERC Order Section 739 and 748.*

**Reference to prior version:** (Part 1.5) New Requirement

**Change Description and Justification:** (Part 1.5)

*Added requirement to address FERC Order No. 706, Paragraph 706.*

### **Rationale for R2:**

The implementation of an effective recovery plan mitigates the risk to the reliable operation of the BES by reducing the time to recover from various hazards affecting BES Cyber Systems. This requirement ensures continued implementation of the response plans.

Requirement Part 2.2 provides further assurance in the information (e.g. backup tapes, mirrored hot-sites, etc.) necessary to recover BES Cyber Systems. A full test is not feasible in most instances due to the amount of recovery information, and the Responsible Entity must determine a sampling that provides assurance in the usability of the information.

**Summary of Changes.** Added operational testing for recovery of BES Cyber Systems.

**Reference to prior version:** (Part 2.1) CIP-009, R2

**Change Description and Justification:** (Part 2.1)

*Minor wording change; essentially unchanged.*

**Reference to prior version:** (Part 2.2) CIP-009, R5

**Change Description and Justification:** (Part 2.2)

*Specifies what to test and makes clear the test can be a representative sampling. These changes, along with Requirement Part 1.4 address the FERC Order No. 706, Paragraphs 739 and 748 related to testing of backups by providing high confidence the information will actually recover the system as necessary.*

**Reference to prior version:** (Part 2.3) CIP-009, R2

**Change Description and Justification:** (Part 2.3)

*Addresses FERC Order No. 706, Paragraph 725 to add the requirement that the recovery plan test be a full operational test once every 3 years.*

**Rationale for R3:**

To improve the effectiveness of BES Cyber System recovery plan(s) following a test, and to ensure the maintenance and distribution of the recovery plan(s). Responsible Entities achieve this by (i) performing a lessons learned review in 3.1 and (ii) revising the plan in 3.2 based on specific changes in the organization or technology that would impact plan execution. In both instances when the plan needs to change, the Responsible Entity updates and distributes the plan.

**Summary of Changes:** Makes clear when to perform lessons learned review of the plan and specifies the timeframe for updating the recovery plan.

**Reference to prior version:** (Part 3.1) CIP-009, R1 and R3

**Change Description and Justification:** (Part 3.1)

*Added the timeframes for performing lessons learned and completing the plan updates. This requirement combines all three activities in one place. Where previous versions specified 30 calendar days for performing lessons learned, followed by additional time for updating recovery plans and notification, this requirement combines those activities into a single timeframe.*

**Reference to prior version:** (Part 3.2) New Requirement

**Change Description and Justification:** (Part 3.2)

*Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the specific changes that would require an update.*

**Version History**

| Version | Date    | Action  | Change Tracking |
|---------|---------|---|-----------------|
| 1       | 1/16/06 | R3.2 — Change “Control Center” to “control center”  | 3/24/06         |
| 2       | 9/30/09 | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a Responsible Entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |                 |

Guidelines and Technical Basis

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|      |          |  |  |
|------|----------|--|--|
| 3    |          | Updated version number from -2 to -3<br>In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009. |  |
| 3    | 12/16/09 | Approved by the NERC Board of Trustees.  | Update   |
| 3    | 3/31/10  | Approved by FERC.  |  |
| 4    | 12/30/10 | Modified to add specific criteria for Critical Asset identification.   | Update   |
| 4    | 1/24/11  | Approved by the NERC Board of Trustees.  |  |
| 5    | 11/26/12 | Adopted by the NERC Board of Trustees.   | Modified to coordinate with other CIP standards and to revise format to use RBS Template.    |
| 5    | 11/22/13 | FERC Order issued approving CIP-009-5. (Order becomes effective on 2/3/14.)  |  |
| 5(X) | TBD      | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Cyber Security — Recovery Plans for BES Cyber Systems
2. **Number:** CIP-009-5(X)
3. **Purpose:** To recover reliability functions performed by BES Cyber Systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**

#### 4.1.7 Transmission Operator

#### 4.1.8 Transmission Owner

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-009-5(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.



**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-009-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-009-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-009-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to BES Cyber Systems located at a Control Center and categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples include, but are not limited to firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

**B. Requirements and Measures**

- R1.** Each Responsible Entity shall have one or more documented recovery plans that collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning].
- M1.** Evidence must include the documented recovery plan(s) that collectively include the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*.

| CIP-009-5(X) Table R1 – Recovery Plan Specifications |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements                                       | Measures  |
| 1.1  | High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol><br>Medium Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | Conditions for activation of the recovery plan(s). | An example of evidence may include, but is not limited to, one or more plans that include language identifying conditions for activation of the recovery plan(s). |

CIP-009-5(X) Table R1 – Recovery Plan Specifications

| Part | Applicable Systems  | Requirements   | Measures  |
|------|---|--|---|
| 1.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Roles and responsibilities of responders.</p>   | <p>An example of evidence may include, but is not limited to, one or more recovery plans that include language identifying the roles and responsibilities of responders.</p>                        |
| 1.3  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>One or more processes for the backup and storage of information required to recover BES Cyber System functionality.</p> | <p>An example of evidence may include, but is not limited to, documentation of specific processes for the backup and storage of information required to recover BES Cyber System functionality.</p> |

CIP-009-5(X) Table R1 – Recovery Plan Specifications

| Part | Applicable Systems   | Requirements  | Measures   |
|------|--|---|--|
| 1.4  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>One or more processes to verify the successful completion of the backup processes in Part 1.3 and to address any backup failures.</p>  | <p>An example of evidence may include, but is not limited to, logs, workflow or other documentation confirming that the backup process completed successfully and backup failures, if any, were addressed.</p> |
| 1.5  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol>                    | <p>One or more processes to preserve data, per Cyber Asset capability, for determining the cause of a Cyber Security Incident that triggers activation of the recovery plan(s). Data preservation should not impede or restrict recovery.</p> | <p>An example of evidence may include, but is not limited to, procedures to preserve data, such as preserving a corrupted drive or making a data mirror of the system before proceeding with recovery.</p>     |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, its documented recovery plan(s) to collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-time Operations.]
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*.

| CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing |  |  |   |
|--|--|--|---|
| Part   | Applicable Systems   | Requirements   | Measures  |
| 2.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Test each of the recovery plans referenced in Requirement R1 at least once every 15 calendar months:</p> <ul style="list-style-type: none"> <li>• By recovering from an actual incident;</li> <li>• With a paper drill or tabletop exercise; or</li> <li>• With an operational exercise.</li> </ul> | <p>An example of evidence may include, but is not limited to, dated evidence of a test (by recovering from an actual incident, with a paper drill or tabletop exercise, or with an operational exercise) of the recovery plan at least once every 15 calendar months. For the paper drill or full operational exercise, evidence may include meeting notices, minutes, or other records of exercise findings.</p> |

| CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 2.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Test a representative sample of information used to recover BES Cyber System functionality at least once every 15 calendar months to ensure that the information is useable and is compatible with current configurations.</p> <p>An actual recovery that incorporates the information used to recover BES Cyber System functionality substitutes for this test.</p> | <p>An example of evidence may include, but is not limited to, operational logs or test results with criteria for testing the usability (e.g. sample tape load, browsing tape contents) and compatibility with current system configurations (e.g. manual or automated comparison checkpoints between backup media contents and current configuration).</p>   |
| 2.3  | High Impact BES Cyber Systems  | <p>Test each of the recovery plans referenced in Requirement R1 at least once every 36 calendar months through an operational exercise of the recovery plans in an environment representative of the production environment.</p> <p>An actual recovery response may substitute for an operational exercise.</p>   | <p>Examples of evidence may include, but are not limited to, dated documentation of:</p> <ul style="list-style-type: none"> <li>• An operational exercise at least once every 36 calendar months between exercises, that demonstrates recovery in a representative environment; or</li> <li>• An actual recovery response that occurred within the 36 calendar month timeframe that exercised the recovery plans.</li> </ul> |



**R3.** Each Responsible Entity shall maintain each of its recovery plans in accordance with each of the applicable requirement parts in CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].

**M3.** Acceptable evidence includes, but is not limited to, each of the applicable requirement parts in CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication.

| CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication |  |   |  |
|--|--|---|--|
| Part   | Applicable Systems   | Requirements  | Measures   |
| 3.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>No later than 90 calendar days after completion of a recovery plan test or actual recovery:</p> <ol style="list-style-type: none"> <li>3.1.1. Document any lessons learned associated with a recovery plan test or actual recovery or document the absence of any lessons learned;</li> <li>3.1.2. Update the recovery plan based on any documented lessons learned associated with the plan; and</li> <li>3.1.3. Notify each person or group with a defined role in the recovery plan of the updates to the recovery plan based on any documented lessons learned.</li> </ol> | <p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated documentation of identified deficiencies or lessons learned for each recovery plan test or actual incident recovery or dated documentation stating there were no lessons learned;</li> <li>2. Dated and revised recovery plan showing any changes based on the lessons learned; and</li> <li>3. Evidence of plan update distribution including, but not limited to:                             <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

| CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication |  |  |  |
|--|--|--|--|
| Part   | Applicable Systems   | Requirements   | Measures   |
| 3.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>No later than 60 calendar days after a change to the roles or responsibilities, responders, or technology that the Responsible Entity determines would impact the ability to execute the recovery plan:</p> <ol style="list-style-type: none"> <li>3.2.1. Update the recovery plan; and</li> <li>3.2.2. Notify each person or group with a defined role in the recovery plan of the updates.</li> </ol> | <p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> <li>1. Dated and revised recovery plan with changes to the roles or responsibilities, responders, or technology; and</li> <li>2. Evidence of plan update distribution including, but not limited to:                             <ul style="list-style-type: none"> <li>• Emails;</li> <li>• USPS or other mail service;</li> <li>• Electronic distribution system; or</li> <li>• Training sign-in sheets.</li> </ul> </li> </ol> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon       | VRF    | Violation Severity Levels (CIP-009-5(X)) |  |  |   |
|-----|--------------------|--------|--|--|--|---|
|     |                    |        | Lower VSL                                | Moderate VSL   | High VSL   | Severe VSL  |
| R1  | Long-term Planning | Medium | N/A                                      | The Responsible Entity has developed recovery plan(s), but the plan(s) do not address one of the requirements included in Parts 1.2 through 1.5. | The Responsible Entity has developed recovery plan(s), but the plan(s) do not address two of the requirements included in Parts 1.2 through 1.5. | The Responsible Entity has not created recovery plan(s) for BES Cyber Systems.<br>OR<br>The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address the conditions for activation in Part 1.1.<br>OR<br>The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address three or more of the requirements in Parts 1.2 through 1.5. |

| R #       | Time Horizon  | VRF          | Violation Severity Levels (CIP-009-5(X))   |  |  |   |
|-----------|---|--------------|--|--|--|---|
|           |   |              | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
| <b>R2</b> | <b>Operations Planning<br/>Real-time Operations</b> | <b>Lower</b> | <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 15 calendar months, not exceeding 16 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 15 calendar months, not exceeding 16 calendar months between tests, and</p> | <p>The Responsible Entity has not tested the recovery plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 16 calendar months, not exceeding 17 calendar months between tests, and when tested, any</p> | <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 17 calendar months, not exceeding 18 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 17 calendar months, not exceeding 18 calendar months between tests, and</p> | <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 18 calendar months between tests of the plan. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 and identified deficiencies, but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 but did not identify, assess, or correct the deficiencies. (2.1)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X))  |  |   |   |
|-----|--------------|-----|---|--|---|---|
|     |              |     | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL  |
|     |              |     | <p>when tested, any deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 36 calendar months, not exceeding 37 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p> | <p>deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 37 calendar months, not exceeding 38 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p> | <p>when tested, any deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 38 calendar months, not exceeding 39 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p> | <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 18 calendar months between tests. (2.2)</p> <p>OR</p> <p>The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 and identified deficiencies, but did not assess or correct the deficiencies. (2.2)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | <p>OR</p> <p>The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.3 within 39 calendar months between tests of the plan. (2.3)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part</p> |

| R #       | Time Horizon                 | VRF          | Violation Severity Levels (CIP-009-5(X))   |  |  |  |
|-----------|------------------------------|--------------|--|--|--|--|
|           |                              |              | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|           |                              |              |  |  |  | 2.3 and identified deficiencies, but did not assess or correct the deficiencies. (2.3)<br><br>OR<br><br>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.3 but did not identify, assess, or correct the deficiencies. (2.3) |
| <b>R3</b> | <b>Operations Assessment</b> | <b>Lower</b> | The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 90 and less than 210 calendar days of the update being completed. (3.1.3) | The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.2)<br><br>OR | The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.1) | The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 210 calendar days of each recovery plan test or actual recovery. (3.1.1)  |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X)) |  |   |            |
|-----|--------------|-----|--|--|---|------------|
|     |              |     | Lower VSL                                | Moderate VSL   | High VSL  | Severe VSL |
|     |              |     |  | <p>The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 120 calendar days of the update being completed. (3.1.3)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> <li>• Responders, or</li> </ul> | <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 120 calendar days of each recovery plan test or actual recovery. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> <li>• Roles or responsibilities, or</li> </ul> |            |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-009-5(X)) |   |  |            |
|-----|--------------|-----|--|---|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL  | High VSL   | Severe VSL |
|     |              |     |  | <ul style="list-style-type: none"> <li>• Technology changes.</li> </ul> | <ul style="list-style-type: none"> <li>• Responders, or Technology changes.</li> </ul> |            |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

The following guidelines are available to assist in addressing the required components of a recovery plan:

- NERC, Security Guideline for the Electricity Sector: Continuity of Business Processes and Operations Operational Functions, September 2011, online at <http://www.nerc.com/docs/cip/sgwg/Continuity%20of%20Business%20and%20Operational%20Functions%20FINAL%20102511.pdf>
- National Institute of Standards and Technology, Contingency Planning Guide for Federal Information Systems, Special Publication 800-34 revision 1, May 2010, online at [http://csrc.nist.gov/publications/nistpubs/800-34-rev1/sp800-34-rev1\\_errata-Nov11-2010.pdf](http://csrc.nist.gov/publications/nistpubs/800-34-rev1/sp800-34-rev1_errata-Nov11-2010.pdf)

The term recovery plan is used throughout this Standard to refer to a documented set of instructions and resources needed to recover reliability functions performed by BES Cyber Systems. The recovery plan may exist as part of a larger business continuity or disaster recovery plan, but the term does not imply any additional obligations associated with those disciplines outside of the Requirements.

A documented recovery plan may not be necessary for each applicable BES Cyber System. For example, the short-term recovery plan for a BES Cyber System in a specific substation may be

managed on a daily basis by advanced power system applications such as state estimation, contingency and remedial action, and outage scheduling. One recovery plan for BES Cyber Systems should suffice for several similar facilities such as those found in substations or power plants' facilities.

For Part 1.1, the conditions for activation of the recovery plan should consider viable threats to the BES Cyber System such as natural disasters, computing equipment failures, computing environment failures, and Cyber Security Incidents. A business impact analysis for the BES Cyber System may be useful in determining these conditions.

For Part 1.2, entities should identify the individuals required for responding to a recovery operation of the applicable BES Cyber System.

For Part 1.3, entities should consider the following types of information to recover BES Cyber System functionality:

1. Installation files and media;
2. Current backup tapes and any additional documented configuration settings;
3. Documented build or restoration procedures; and
4. Cross site replication storage.

For Part 1.4, the processes to verify the successful completion of backup processes should include checking for: (1) usability of backup media, (2) logs or inspection showing that information from current, production system could be read, and (3) logs or inspection showing that information was written to the backup media. Test restorations are not required for this Requirement Part. The following backup scenarios provide examples of effective processes to verify successful completion and detect any backup failures:

- Periodic (e.g. daily or weekly) backup process – Review generated logs or job status reports and set up notifications for backup failures.
- Non-periodic backup process– If a single backup is provided during the commissioning of the system, then only the initial and periodic (every 15 months) testing must be done. Additional testing should be done as necessary and can be a part of the configuration change management program.
- Data mirroring – Configure alerts on the failure of data transfer for an amount of time specified by the entity (e.g. 15 minutes) in which the information on the mirrored disk may no longer be useful for recovery.
- Manual configuration information – Inspect the information used for recovery prior to storing initially and periodically (every 15 months). Additional inspection should be done as necessary and can be a part of the configuration change management program.

The plan must also include processes to address backup failures. These processes should specify the response to failure notifications or other forms of identification.

For Part 1.5, the recovery plan must include considerations for preservation of data to determine the cause of a Cyber Security Incident. Because it is not always possible to initially

know if a Cyber Security Incident caused the recovery activation, the data preservation procedures should be followed until such point a Cyber Security Incident can be ruled out. CIP-008 addresses the retention of data associated with a Cyber Security Incident.

### **Requirement R2:**

A Responsible Entity must exercise each BES Cyber System recovery plan every 15 months. However, this does not necessarily mean that the entity must test each plan individually. BES Cyber Systems that are numerous and distributed, such as those found at substations, may not require an individual recovery plan and the associated redundant facilities since reengineering and reconstruction may be the generic response to a severe event. Conversely, there is typically one control center per bulk transmission service area that requires a redundant or backup facility. Because of these differences, the recovery plans associated with control centers differ a great deal from those associated with power plants and substations.

A recovery plan test does not necessarily cover all aspects of a recovery plan and failure scenarios, but the test should be sufficient to ensure the plan is up to date and at least one restoration process of the applicable cyber systems is covered.

Entities may use an actual recovery as a substitute for exercising the plan every 15 months. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, "A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. [Table top exercises (TTX)] can be used to assess plans, policies, and procedures."

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, "[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and 'boots on the ground' response (e.g., firefighters decontaminating mock victims)."

For Part 2.2, entities should refer to the backup and storage of information required to recover BES Cyber System functionality in Requirement Part 1.3. This provides additional assurance that the information will actually recover the BES Cyber System as necessary. For most complex computing equipment, a full test of the information is not feasible. Entities should determine the representative sample of information that provides assurance in the processes for Requirement Part 1.3. The test must include steps for ensuring the information is useable and current. For backup media, this can include testing a representative sample to make sure the information can be loaded, and checking the content to make sure the information reflects the current configuration of the applicable Cyber Assets.

### **Requirement R3:**

This requirement ensures entities maintain recovery plans. There are two requirement parts that trigger plan updates: (1) lessons learned and (2) organizational or technology changes.

The documentation of lessons learned is associated with each recovery activation, and it involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the recovery operation in recognition that complex recovery activities can take a few days or weeks to complete. The process of conducting lessons learned can involve the recovery team discussing the incident to determine gaps or areas of improvement within the plan. It is possible to have a recovery activation without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the recovery activation.

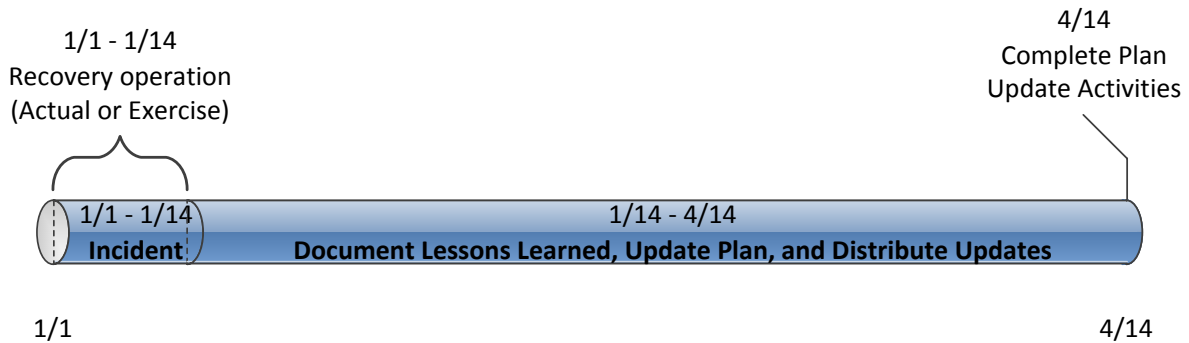


Figure 1: CIP-009-5(X) R3 Timeline

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the recovery and documenting the lessons learned as soon after the recovery activation as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the recovery team.

The plan change requirement is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems, or ticketing systems.

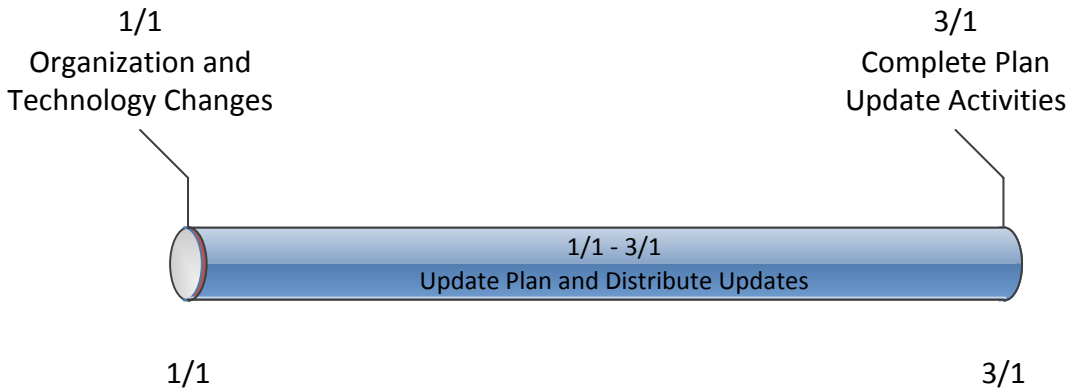


Figure 2: Timeline for Plan Changes in 3.2

When notifying individuals of response plan changes, entities should keep in mind that recovery plans may be considered BES Cyber System Information, and they should take the appropriate measures to prevent unauthorized disclosure of recovery plan information. For example, the recovery plan itself, or other sensitive information about the recovery plan, should be redacted from Email or other unencrypted transmission.

**Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

**Rationale for R1:**

Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned recovery capability is, therefore, necessary for rapidly recovering from incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services so that planned and consistent recovery action to restore BES Cyber System functionality occurs.

**Summary of Changes:** Added provisions to protect data that would be useful in the investigation of an event that results in the need for a Cyber System recovery plan to be utilized.

**Reference to prior version:** (Part 1.1) CIP-009, R1.1

**Change Description and Justification:** (Part 1.1)

*Minor wording changes; essentially unchanged.*

**Reference to prior version:** (Part 1.2) CIP-009, R1.2

**Change Description and Justification:** (Part 1.2)

*Minor wording changes; essentially unchanged.*



**Reference to prior version:** (Part 1.3) CIP-009, R4

**Change Description and Justification:** (Part 1.3)

*Addresses FERC Order Paragraph 739 and 748. The modified wording was abstracted from Paragraph 744.*

**Reference to prior version:** (Part 1.4) New Requirement

**Change Description and Justification:** (Part 1.4)

*Addresses FERC Order Section 739 and 748.*

**Reference to prior version:** (Part 1.5) New Requirement

**Change Description and Justification:** (Part 1.5)

*Added requirement to address FERC Order No. 706, Paragraph 706.*

### **Rationale for R2:**

The implementation of an effective recovery plan mitigates the risk to the reliable operation of the BES by reducing the time to recover from various hazards affecting BES Cyber Systems. This requirement ensures continued implementation of the response plans.

Requirement Part 2.2 provides further assurance in the information (e.g. backup tapes, mirrored hot-sites, etc.) necessary to recover BES Cyber Systems. A full test is not feasible in most instances due to the amount of recovery information, and the Responsible Entity must determine a sampling that provides assurance in the usability of the information.

**Summary of Changes.** Added operational testing for recovery of BES Cyber Systems.

**Reference to prior version:** (Part 2.1) CIP-009, R2

**Change Description and Justification:** (Part 2.1)

*Minor wording change; essentially unchanged.*

**Reference to prior version:** (Part 2.2) CIP-009, R5

**Change Description and Justification:** (Part 2.2)

*Specifies what to test and makes clear the test can be a representative sampling. These changes, along with Requirement Part 1.4 address the FERC Order No. 706, Paragraphs 739 and 748 related to testing of backups by providing high confidence the information will actually recover the system as necessary.*

**Reference to prior version:** (Part 2.3) CIP-009, R2

**Change Description and Justification:** (Part 2.3)

*Addresses FERC Order No. 706, Paragraph 725 to add the requirement that the recovery plan test be a full operational test once every 3 years.*

**Rationale for R3:**

To improve the effectiveness of BES Cyber System recovery plan(s) following a test, and to ensure the maintenance and distribution of the recovery plan(s). Responsible Entities achieve this by (i) performing a lessons learned review in 3.1 and (ii) revising the plan in 3.2 based on specific changes in the organization or technology that would impact plan execution. In both instances when the plan needs to change, the Responsible Entity updates and distributes the plan.

**Summary of Changes:** Makes clear when to perform lessons learned review of the plan and specifies the timeframe for updating the recovery plan.

**Reference to prior version:** (Part 3.1) CIP-009, R1 and R3

**Change Description and Justification:** (Part 3.1)

*Added the timeframes for performing lessons learned and completing the plan updates. This requirement combines all three activities in one place. Where previous versions specified 30 calendar days for performing lessons learned, followed by additional time for updating recovery plans and notification, this requirement combines those activities into a single timeframe.*

**Reference to prior version:** (Part 3.2) New Requirement

**Change Description and Justification:** (Part 3.2)

*Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the specific changes that would require an update.*

**Version History**

| Version | Date    | Action  | Change Tracking |
|---------|---------|---|-----------------|
| 1       | 1/16/06 | R3.2 — Change “Control Center” to “control center”  | 3/24/06         |
| 2       | 9/30/09 | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a Responsible Entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |                 |

Guidelines and Technical Basis

|             |            |  |   |
|-------------|------------|--|---|
| 3           |            | Updated version number from -2 to -3<br>In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009. |   |
| 3           | 12/16/09   | Approved by the NERC Board of Trustees.  | Update  |
| 3           | 3/31/10    | Approved by FERC.  |   |
| 4           | 12/30/10   | Modified to add specific criteria for Critical Asset identification.   | Update  |
| 4           | 1/24/11    | Approved by the NERC Board of Trustees.  |   |
| 5           | 11/26/12   | Adopted by the NERC Board of Trustees.   | Modified to coordinate with other CIP standards and to revise format to use RBS Template.           |
| 5           | 11/22/13   | FERC Order issued approving CIP-009-5. (Order becomes effective on 2/3/14.)  |   |
| <u>5(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** Cyber Security — Configuration Change Management and Vulnerability Assessments
2. **Number:** CIP-010-1(X)
3. **Purpose:** To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**

**4.1.6 Reliability Coordinator**

**4.1.7 Transmission Operator**

**4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-010-1(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-010-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-010-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-010-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk

Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the applicability column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System



**B. Requirements and Measures**

**R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

**M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-010-1(X) Table R1 – Configuration Change Management |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 1.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Develop a baseline configuration, individually or by group, which shall include the following items:</p> <ol style="list-style-type: none"> <li>1.1.1. Operating system(s) (including version) or firmware where no independent operating system exists;</li> <li>1.1.2. Any commercially available or open-source application software (including version) intentionally installed;</li> <li>1.1.3. Any custom software installed;</li> <li>1.1.4. Any logical network accessible ports; and</li> <li>1.1.5. Any security patches applied.</li> </ol> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• A spreadsheet identifying the required items of the baseline configuration for each Cyber Asset, individually or by group; or</li> <li>• A record in an asset management system that identifies the required items of the baseline configuration for each Cyber Asset, individually or by group.</li> </ul> |
|   |   |   |   |

| CIP-010-1(X) Table R1 – Configuration Change Management |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 1.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Authorize and document changes that deviate from the existing baseline configuration.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• A change request record and associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a change management system for each change; or</li> <li>• Documentation that the change was performed in accordance with the requirement.</li> </ul> |

| CIP-010-1(X) Table R1 – Configuration Change Management |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 1.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 calendar days of completing the change.</p>   | <p>An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 calendar days of the date of the completion of the change.</p> |
| 1.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For a change that deviates from the existing baseline configuration:</p> <ol style="list-style-type: none"> <li>1.4.1. Prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change;</li> <li>1.4.2. Following the change, verify that required cyber security controls determined in 1.4.1 are not adversely affected; and</li> <li>1.4.3. Document the results of the verification.</li> </ol> | <p>An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.</p>                                 |

| CIP-010-1(X) Table R1 – Configuration Change Management |                               |  |  |
|---|-------------------------------|--|--|
| Part  | Applicable Systems            | Requirements   | Measures   |
| 1.5   | High Impact BES Cyber Systems | <p>Where technically feasible, for each change that deviates from the existing baseline configuration:</p> <p>1.5.1. Prior to implementing any change in the production environment, test the changes in a test environment or test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and</p> <p>1.5.2. Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p> | <p>An example of evidence may include, but is not limited to, a list of cyber security controls tested along with successful test results and a list of differences between the production and test environments with descriptions of how any differences were accounted for, including of the date of the test.</p> |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-010-1(X) Table R2 – Configuration Monitoring |   |  |   |
|--|---|--|---|
| Part   | Applicable Systems  | Requirements   | Measures  |
| 2.1  | High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes. | An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected. |
|  |   |  |   |

- R3.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3– Vulnerability Assessments*. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning and Operations Planning]
- M3.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3 – Vulnerability Assessments* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-010-1(X) Table R3 – Vulnerability Assessments |   |  |  |
|---|---|--|--|
| Part  | Applicable Systems  | Requirements   | Measures   |
| 3.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>At least once every 15 calendar months, conduct a paper or active vulnerability assessment.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• A document listing the date of the assessment (performed at least once every 15 calendar months), the controls assessed for each BES Cyber System along with the method of assessment;; or</li> <li>• A document listing the date of the assessment and the output of any tools used to perform the assessment.</li> </ul> |

| CIP-010-1(X) Table R3 – Vulnerability Assessments |                               |   |  |
|---|-------------------------------|---|--|
| Part  | Applicable Systems            | Requirements  | Measures   |
| 3.2   | High Impact BES Cyber Systems | <p>Where technically feasible, at least once every 36 calendar months:</p> <p>3.2.1 Perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration of the BES Cyber System in a production environment; and</p> <p>3.2.2 Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p> | <p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 calendar months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.</p> |

| CIP-010-1(X) Table R3 – Vulnerability Assessments |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 3.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PCA</li> </ol>  | <p>Prior to adding a new applicable Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset, except for CIP Exceptional Circumstances and like replacements of the same type of Cyber Asset with a baseline configuration that models an existing baseline configuration of the previous or other existing Cyber Asset.</p> | <p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the new Cyber Asset) and the output of any tools used to perform the assessment.</p>   |
| 3.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Document the results of the assessments conducted according to Parts 3.1, 3.2, and 3.3 and the action plan to remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.</p>  | <p>An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).</p> |



## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-010-1(X))   |  |  |  |
|-----------|----------------------------|---------------|--|--|--|--|
|           |                            |               | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
| <b>R1</b> | <b>Operations Planning</b> | <b>Medium</b> | <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only four of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline</p> | <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only three of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 and</p> | <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only two of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 and identified</p> | <p>The Responsible Entity has not documented or implemented any configuration change management process(es). (R1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only one of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))  |  |  |  |
|-----|--------------|-----|---|--|--|--|
|     |              |     | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1)</p> <p>OR</p> | <p>identified deficiencies but did not assess and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to determine required</p> | <p>deficiencies but did not assess and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has a process(es) that requires authorization and documentation for</p> | <p>implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify,</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration and identified deficiencies in the verification documentation but did not assess or correct the deficiencies. (1.4.3)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration but did not identify,</p> | <p>security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration and identified deficiencies in the determination of affected security controls, but did not assess, or correct the deficiencies. (1.4.1)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline</p> | <p>changes that deviate from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) that requires authorization and documentation for changes that deviate from the existing baseline configuration but did not identify, assess, or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to update</p> | <p>assess, and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) that requires authorization and documentation of changes that deviate from the existing baseline configuration. (1.2)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration.(1.3)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))                                       |   |   |   |
|-----|--------------|-----|--|---|---|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | assess, or correct the deficiencies in the verification documentation. (1.4.3) | configuration but did not identify, assess, or correct the deficiencies in the determination of affected security controls. (1.4.1) | baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.3)<br><br>OR<br><br>The Responsible Entity has a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration but did not identify, assess, | OR<br><br>The Responsible Entity does not have a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration. (1.4.1)<br><br>OR<br><br>The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration but did |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | or correct the deficiencies. (1.3)<br>OR<br>The Responsible Entity has a process(es) to verify that required security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration and identified deficiencies in required controls, but did not assess, or correct the deficiencies. (1.4.2)<br>OR<br>The Responsible Entity has a process(es) to verify that required | not verify and document that the required controls were not adversely affected following the change. (1.4.2 & 1.4.3)<br>OR<br>The Responsible Entity does not have a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration. (1.5.1)<br>OR<br>The Responsible Entity does not have a process to document the test results and, if using a test environment, |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |   |   |
|-----|--------------|-----|--|--------------|---|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
|     |              |     |  |              | <p>security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration but did not identify, assess, or correct the deficiencies in the required controls. (1.4.2)</p> <p>OR</p> <p>The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration, and identified deficiencies but did not assess or correct</p> | <p>document the differences between the test and production environments. (1.5.2)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |  |            |
|-----|--------------|-----|--|--------------|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL |
|     |              |     |  |              | the deficiencies. (1.5.1)<br>OR<br>The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration but did not identify, assess, or correct the deficiencies. (1.5.1)<br>OR<br>The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production |            |



| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-010-1(X)) |              |  |  |
|-----------|----------------------------|---------------|--|--------------|--|--|
|           |                            |               | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL   |
|           |                            |               |  |              | <p>environments and identified deficiencies but did not assess or correct the deficiencies. (1.5.2)</p> <p>OR</p> <p>The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production environments, but did not identify, assess, or correct the deficiencies. (1.5.2)</p> |  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Medium</b> | N/A                                      | N/A          | N/A  | The Responsible Entity has not documented or implemented a process(es) to monitor for, |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days. (2.1)<br>OR<br>The Responsible Entity has documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days and identified deficiencies but did not assess or correct the deficiencies. (2.1)<br>OR<br>The Responsible Entity has |

| R #       | Time Horizon                                      | VRF           | Violation Severity Levels (CIP-010-1(X))   |   |   |  |
|-----------|---|---------------|--|---|---|--|
|           |   |               | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|           |   |               |  |   |   | documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days but did not identify, assess, or correct the deficiencies. (2.1) |
| <b>R3</b> | <b>Long-term Planning and Operations Planning</b> | <b>Medium</b> | The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 15 months, | The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 18 months, but less than 21, months | The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 21 months, but less than 24 months, | The Responsible Entity has not implemented any vulnerability assessment processes for one of its applicable BES Cyber Systems. (R3)<br><br>OR<br><br>The Responsible Entity has implemented one or more documented                     |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))  |   |   |  |
|-----|--------------|-----|---|---|---|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | <p>but less than 18 months, since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 36 months, but less than 39 months, since the last active assessment on one of its applicable BES</p> | <p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 39 months, but less than 42 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p> | <p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 42 months, but less than 45 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p> | <p>vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 24 months since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 45 months since the last active</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     | Cyber Systems.<br>(3.2)                  |              |          | assessment on one of its applicable BES Cyber Systems.(3.2)<br>OR<br>The Responsible Entity has implemented and documented one or more vulnerability assessment processes for each of its applicable BES Cyber Systems, but did not perform the active vulnerability assessment in a manner that models an existing baseline configuration of its applicable BES Cyber Systems. (3.3)<br>OR<br>The Responsible Entity has implemented one or more documented |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | vulnerability assessment processes for each of its applicable BES Cyber Systems, but has not documented the results of the vulnerability assessments, the action plans to remediate or mitigate vulnerabilities identified in the assessments, the planned date of completion of the action plan, and the execution status of the mitigation plans. (3.4) |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

##### Baseline Configuration

The concept of establishing a Cyber Asset’s baseline configuration is meant to provide clarity on requirement language found in previous CIP standard versions. Modification of any item within an applicable Cyber Asset’s baseline configuration provides the triggering mechanism for when entities must apply change management processes.

Baseline configurations in CIP-010 consist of five different items: Operating system/firmware, commercially available software or open-source application software, custom software, logical network accessible port identification, and security patches. Operating system information identifies the software and version that is in use on the Cyber Asset. In cases where an independent operating system does not exist (such as for a protective relay), then firmware information should be identified. Commercially available or open-source application software identifies applications that were intentionally installed on the cyber asset. The use of the term “intentional” was meant to ensure that only software applications that were determined to be necessary for Cyber Asset use should be included in the baseline configuration. The SDT does not intend for notepad, calculator, DLL, device drivers, or other applications included in an operating system package as commercially available or open-source application software to be



included. Custom software installed may include scripts developed for local entity functions or other custom software developed for a specific task or function for the entity's use. If additional software was intentionally installed and is not commercially available or open-source, then this software could be considered custom software. If a specific device needs to communicate with another device outside the network, communications need to be limited to only the devices that need to communicate per the requirement in CIP-007-5(X). Those ports which are accessible need to be included in the baseline. Security patches applied would include all historical and current patches that have been applied on the cyber asset. While CIP-007-5(X) R2.1 requires entities to track, evaluate, and install security patches, CIP-010 R1.1.5 requires entities to list all applied historical and current patches.

Further guidance can be understood with the following example that details the baseline configuration for a serial-only microprocessor relay:

Asset #051028 at Substation Alpha

- R1.1.1 – Firmware: [MANUFACTURER]-[MODEL]-XYZ-1234567890-ABC
- R1.1.2 – Not Applicable
- R1.1.3 – Not Applicable
- R1.1.4 – Not Applicable
- R1.1.5 – Patch 12345, Patch 67890, Patch 34567, Patch 437823

Also, for a typical IT system, the baseline configuration could reference an IT standard that includes configuration details. An entity would be expected to provide that IT standard as part of their compliance evidence.

### **Cyber Security Controls**

The use of cyber security controls refers specifically to controls referenced and applied according to CIP-005 and CIP-007. The concept presented in the relevant requirement sub-parts in CIP-010 R1 is that an entity is to identify/verify controls from CIP-005 and CIP-007 that could be impacted for a change that deviates from the existing baseline configuration. The SDT does not intend for Responsible Entities to identify/verify all controls located within CIP-005 and CIP-007 for each change. The Responsible Entity is only to identify/verify those control(s) that could be affected by the baseline configuration change. For example, changes that affect logical network ports would only involve CIP-007 R1 (Ports and Services), while changes that affect security patches would only involve CIP-007 R2 (Security Patch Management). The SDT chose not to identify the specific requirements from CIP-005 and CIP-007 in CIP-010 language as the intent of the related requirements is to be able to identify/verify any of the controls in those standards that are affected as a result of a change to the baseline configuration. The SDT believes it possible that all requirements from CIP-005 and CIP-007 may be identified for a

major change to the baseline configuration, and therefore, CIP-005 and CIP-007 was cited at the standard-level versus the requirement-level.

### **Test Environment**

The Control Center test environment (or production environment where the test is performed in a manner that minimizes adverse effects) should model the baseline configuration, but may have a different set of components. For instance, an entity may have a BES Cyber System that runs a database on one component and a web server on another component. The test environment may have the same operating system, security patches, network accessible ports, and software, but have both the database and web server running on a single component instead of multiple components.

Additionally, the Responsible Entity should note that wherever a test environment (or production environment where the test is performed in a manner that minimizes adverse effects) is mentioned, the requirement is to “model” the baseline configuration and not duplicate it exactly. This language was chosen deliberately in order to allow for individual elements of a BES Cyber System at a Control Center to be modeled that may not otherwise be able to be replicated or duplicated exactly; such as, but not limited to, a legacy map-board controller or the numerous data communication links from the field or to other Control Centers (such as by ICCP).

### **Requirement R2:**

The SDT’s intent of R2 is to require automated monitoring of the BES Cyber System. However, the SDT understands that there may be some Cyber Assets where automated monitoring may not be possible (such as a GPS time clock). For that reason, automated technical monitoring was not explicitly required, and a Responsible Entity may choose to accomplish this requirement through manual procedural controls.

### **Requirement R3:**

The Responsible Entity should note that the requirement provides a distinction between paper and active vulnerability assessments. The justification for this distinction is well-documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking. In developing their vulnerability assessment processes, Responsible Entities are strongly encouraged to include at least the following elements, several of which are referenced in CIP-005 and CIP-007:

Paper Vulnerability Assessment:

1. Network Discovery - A review of network connectivity to identify all Electronic Access Points to the Electronic Security Perimeter.
2. Network Port and Service Identification - A review to verify that all enabled ports and services have an appropriate business justification.

3. Vulnerability Review - A review of security rule-sets and configurations including controls for default accounts, passwords, and network management community strings.
4. Wireless Review - Identification of common types of wireless networks (such as 802.11a/b/g/n) and a review of their controls if they are in any way used for BES Cyber System communications.

### Active Vulnerability Assessment:

1. Network Discovery - Use of active discovery tools to discover active devices and identify communication paths in order to verify that the discovered network architecture matches the documented architecture.
2. Network Port and Service Identification – Use of active discovery tools (such as Nmap) to discover open ports and services.
3. Vulnerability Scanning – Use of a vulnerability scanning tool to identify network accessible ports and services along with the identification of known vulnerabilities associated with services running on those ports.
4. Wireless Scanning – Use of a wireless scanning tool to discover wireless signals and networks in the physical perimeter of a BES Cyber System. Serves to identify unauthorized wireless devices within the range of the wireless scanning tool.

In addition, Responsible Entities are strongly encouraged to review NIST SP800-115 for additional guidance on how to conduct a vulnerability assessment.

### **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

#### **Rationale for R1:**

The configuration change management processes are intended to prevent unauthorized modifications to BES Cyber Systems.

**Reference to prior version:** (Part 1.1) New Requirement

**Change Rationale:** (Part 1.1)

*The baseline configuration requirement was incorporated from the DHS Catalog for Control Systems Security. The baseline requirement is also intended to clarify precisely when a change management process must be invoked and which elements of the configuration must be examined.*

**Reference to prior version:** (Part 1.2) CIP-007-3, R9; CIP-003-3, R6

**Change Rationale:** (Part 1.2)

*The SDT added requirement to explicitly authorize changes. This requirement was previously implied by CIP-003-3, Requirement R6.*

**Reference to prior version:** (Part 1.3) CIP-007-3, R9; CIP-005-3, R5

**Change Rationale:** (Part 1.3)

*Document maintenance requirement due to a BES Cyber System change is equivalent to the requirements in the previous versions of the standard.*

**Reference to prior version:** (Part 1.4) CIP-007-3, R1

**Change Rationale:** (Part 1.4)

*The SDT attempted to provide clarity on when testing must occur and removed requirement for specific test procedures because it is implicit in the performance of the requirement.*

**Reference to prior version:** (Part 1.5) CIP-007-3, R1

**Change Rationale:** (Part 1.5)

*This requirement provides clarity on when testing must occur and requires additional testing to ensure that accidental consequences of planned changes are appropriately managed.*

*This change addresses FERC Order No. 706, Paragraphs 397, 609, 610, and 611.*

**Rationale for R2:**

The configuration monitoring processes are intended to detect unauthorized modifications to BES Cyber Systems.

**Reference to prior version:** (Part 2.1) New Requirement

**Change Rationale:** (Part 2.1)

*The monitoring of the configuration of the BES Cyber System provides an express acknowledgement of the need to consider malicious actions along with intentional changes.*

*This requirement was added after review of the DHS Catalog of Control System Security and to address FERC Order No. 706, Paragraph 397.*

*Thirty-five Calendar days allows for a “once-a-month” frequency with slight flexibility to account for months with 31 days or for beginning or endings of months on weekends.*

**Rationale for R3:**

The vulnerability assessment processes are intended to act as a component in an overall program to periodically ensure the proper implementation of cyber security controls as well as to continually improve the security posture of BES Cyber Systems.

The vulnerability assessment performed for this requirement may be a component of deficiency identification, assessment, and correction.

**Reference to prior version:** (Part 3.1) CIP-005-4, R4; CIP-007-4, R8

**Change Rationale:** (Part 3.1)

*As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.*

**Reference to prior version:** (Part 3.2) New Requirement

**Change Rationale:** (Part 3.2)

*FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.*

*As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.*

**Reference to prior version:** (Part 3.3) New Requirement

**Change Rationale:** (Part 3.3)

*FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.*

**Reference to prior version:** (Part 3.4) CIP-005-3, R4.5; CIP-007-3, R8.4

**Change Rationale:** (Part 3.4)

*Added a requirement for an entity planned date of completion as per the directive in FERC Order No. 706, Paragraph 643.*

### Version History

| Version | Date     | Action  | Change Tracking  |
|---------|----------|---|--|
| 1       | 11/26/12 | Adopted by the NERC Board of Trustees.                                      | Developed to define the configuration change management and vulnerability assessment requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706. |
| 1       | 11/22/13 | FERC Order issued approving CIP-010-1. (Order becomes effective on 2/3/14.) |  |

## Guidelines and Technical Basis

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|      |     |                                       |  |
|------|-----|---------------------------------------|--|
| 1(X) | TBD | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|------|-----|---------------------------------------|--|

## A. Introduction

1. **Title:** Cyber Security — Configuration Change Management and Vulnerability Assessments
2. **Number:** CIP-010-1(X)
3. **Purpose:** To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**

**4.1.6 Reliability Coordinator**

**4.1.7 Transmission Operator**

**4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-010-1(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.



**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-010-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-010-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-010-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk

Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the applicability column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System

**B. Requirements and Measures**

**R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

**M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-010-1(X) Table R1 – Configuration Change Management |   |   |   |
|---|---|---|---|
| Part  | Applicable Systems  | Requirements  | Measures  |
| 1.1   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Develop a baseline configuration, individually or by group, which shall include the following items:</p> <ol style="list-style-type: none"> <li>1.1.1. Operating system(s) (including version) or firmware where no independent operating system exists;</li> <li>1.1.2. Any commercially available or open-source application software (including version) intentionally installed;</li> <li>1.1.3. Any custom software installed;</li> <li>1.1.4. Any logical network accessible ports; and</li> <li>1.1.5. Any security patches applied.</li> </ol> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• A spreadsheet identifying the required items of the baseline configuration for each Cyber Asset, individually or by group; or</li> <li>• A record in an asset management system that identifies the required items of the baseline configuration for each Cyber Asset, individually or by group.</li> </ul> |
|   |   |   |   |

| CIP-010-1(X) Table R1 – Configuration Change Management |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 1.2   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Authorize and document changes that deviate from the existing baseline configuration.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• A change request record and associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a change management system for each change; or</li> <li>• Documentation that the change was performed in accordance with the requirement.</li> </ul> |

| CIP-010-1(X) Table R1 – Configuration Change Management |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 1.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 calendar days of completing the change.</p>   | <p>An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 calendar days of the date of the completion of the change.</p> |
| 1.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>For a change that deviates from the existing baseline configuration:</p> <ol style="list-style-type: none"> <li>1.4.1. Prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change;</li> <li>1.4.2. Following the change, verify that required cyber security controls determined in 1.4.1 are not adversely affected; and</li> <li>1.4.3. Document the results of the verification.</li> </ol> | <p>An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.</p>                                 |

| CIP-010-1(X) Table R1 – Configuration Change Management |                               |  |  |
|---|-------------------------------|--|--|
| Part  | Applicable Systems            | Requirements   | Measures   |
| 1.5   | High Impact BES Cyber Systems | <p>Where technically feasible, for each change that deviates from the existing baseline configuration:</p> <p>1.5.1. Prior to implementing any change in the production environment, test the changes in a test environment or test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and</p> <p>1.5.2. Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p> | <p>An example of evidence may include, but is not limited to, a list of cyber security controls tested along with successful test results and a list of differences between the production and test environments with descriptions of how any differences were accounted for, including of the date of the test.</p> |

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring*. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*.
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-010-1(X) Table R2 – Configuration Monitoring |   |  |   |
|--|---|--|---|
| Part   | Applicable Systems  | Requirements   | Measures  |
| 2.1  | High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PCA</li> </ol> | Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes. | An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected. |
|  |   |  |   |

- R3.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3– Vulnerability Assessments*. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning and Operations Planning]*
- M3.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3 – Vulnerability Assessments* and additional evidence to demonstrate implementation as described in the Measures column of the table.



CIP-010-1(X) Table R3 – Vulnerability Assessments

| Part | Applicable Systems  | Requirements   | Measures   |
|------|---|--|--|
| 3.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>At least once every 15 calendar months, conduct a paper or active vulnerability assessment.</p> | <p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• A document listing the date of the assessment (performed at least once every 15 calendar months), the controls assessed for each BES Cyber System along with the method of assessment;; or</li> <li>• A document listing the date of the assessment and the output of any tools used to perform the assessment.</li> </ul> |

| CIP-010-1(X) Table R3 – Vulnerability Assessments |                               |   |  |
|---|-------------------------------|---|--|
| Part  | Applicable Systems            | Requirements  | Measures   |
| 3.2   | High Impact BES Cyber Systems | <p>Where technically feasible, at least once every 36 calendar months:</p> <p>3.2.1 Perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration of the BES Cyber System in a production environment; and</p> <p>3.2.2 Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p> | <p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 calendar months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.</p> |

| CIP-010-1(X) Table R3 – Vulnerability Assessments |   |  |   |
|---|---|--|---|
| Part  | Applicable Systems  | Requirements   | Measures  |
| 3.3   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PCA</li> </ol>  | <p>Prior to adding a new applicable Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset, except for CIP Exceptional Circumstances and like replacements of the same type of Cyber Asset with a baseline configuration that models an existing baseline configuration of the previous or other existing Cyber Asset.</p> | <p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the new Cyber Asset) and the output of any tools used to perform the assessment.</p>   |
| 3.4   | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Document the results of the assessments conducted according to Parts 3.1, 3.2, and 3.3 and the action plan to remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.</p>  | <p>An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).</p> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-010-1(X))   |  |  |  |
|-----------|----------------------------|---------------|--|--|--|--|
|           |                            |               | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
| <b>R1</b> | <b>Operations Planning</b> | <b>Medium</b> | <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only four of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline</p> | <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only three of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 and</p> | <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only two of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 and identified</p> | <p>The Responsible Entity has not documented or implemented any configuration change management process(es). (R1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only one of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))   |   |   |   |
|-----|--------------|-----|--|---|---|---|
|     |              |     | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1)<br><br>OR<br><br>The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1)<br><br>OR | identified deficiencies but did not assess and correct the deficiencies. (1.1)<br><br>OR<br><br>The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1)<br><br>OR<br><br>The Responsible Entity has a process(es) to determine required | deficiencies but did not assess and correct the deficiencies. (1.1)<br><br>OR<br><br>The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1)<br><br>OR<br><br>The Responsible Entity has a process(es) that requires authorization and documentation for | implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1)<br><br>OR<br><br>The Responsible Entity has documented and implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))  |   |   |   |
|-----|--------------|-----|---|---|---|---|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|     |              |     | <p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration and identified deficiencies in the verification documentation but did not assess or correct the deficiencies. (1.4.3)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration but did not identify,</p> | <p>security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration and identified deficiencies in the determination of affected security controls, but did not assess, or correct the deficiencies. (1.4.1)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline</p> | <p>changes that deviate from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) that requires authorization and documentation for changes that deviate from the existing baseline configuration but did not identify, assess, or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to update</p> | <p>assess, and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) that requires authorization and documentation of changes that deviate from the existing baseline configuration. (1.2)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration.(1.3)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))  |  |  |  |
|-----|--------------|-----|---|--|--|--|
|     |              |     | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|     |              |     | <p>assess, or correct the deficiencies in the verification documentation. (1.4.3)</p> | <p>configuration but did not identify, assess, or correct the deficiencies in the determination of affected security controls. (1.4.1)</p> | <p>baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.3)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration but did not identify, assess,</p> | <p>OR</p> <p>The Responsible Entity does not have a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration. (1.4.1)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration but did</p> |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |   |  |
|-----|--------------|-----|--|--------------|---|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL   |
|     |              |     |  |              | or correct the deficiencies. (1.3)<br>OR<br>The Responsible Entity has a process(es) to verify that required security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration and identified deficiencies in required controls, but did not assess, or correct the deficiencies. (1.4.2)<br>OR<br>The Responsible Entity has a process(es) to verify that required | not verify and document that the required controls were not adversely affected following the change. (1.4.2 & 1.4.3)<br>OR<br>The Responsible Entity does not have a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration. (1.5.1)<br>OR<br>The Responsible Entity does not have a process to document the test results and, if using a test environment, |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |   |   |
|-----|--------------|-----|--|--------------|---|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
|     |              |     |  |              | <p>security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration but did not identify, assess, or correct the deficiencies in the required controls. (1.4.2)</p> <p>OR</p> <p>The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration, and identified deficiencies but did not assess or correct</p> | <p>document the differences between the test and production environments. (1.5.2)</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |  |            |
|-----|--------------|-----|--|--------------|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL |
|     |              |     |  |              | the deficiencies. (1.5.1)<br>OR<br>The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration but did not identify, assess, or correct the deficiencies. (1.5.1)<br>OR<br>The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production |            |

| R #       | Time Horizon               | VRF           | Violation Severity Levels (CIP-010-1(X)) |              |  |  |
|-----------|----------------------------|---------------|--|--------------|--|--|
|           |                            |               | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL   |
|           |                            |               |  |              | <p>environments and identified deficiencies but did not assess or correct the deficiencies. (1.5.2)</p> <p>OR</p> <p>The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production environments, but did not identify, assess, or correct the deficiencies. (1.5.2)</p> |  |
| <b>R2</b> | <b>Operations Planning</b> | <b>Medium</b> | N/A                                      | N/A          | N/A  | The Responsible Entity has not documented or implemented a process(es) to monitor for, |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     |  |              |          | <p>investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days and identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has</p> |

| R #       | Time Horizon                                      | VRF           | Violation Severity Levels (CIP-010-1(X))   |   |   |  |
|-----------|---|---------------|--|---|---|--|
|           |   |               | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|           |   |               |  |   |   | documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days but did not identify, assess, or correct the deficiencies. (2.1) |
| <b>R3</b> | <b>Long-term Planning and Operations Planning</b> | <b>Medium</b> | The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 15 months, | The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 18 months, but less than 21, months | The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 21 months, but less than 24 months, | The Responsible Entity has not implemented any vulnerability assessment processes for one of its applicable BES Cyber Systems. (R3)<br><br>OR<br><br>The Responsible Entity has implemented one or more documented                     |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X))  |   |   |  |
|-----|--------------|-----|---|---|---|--|
|     |              |     | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|     |              |     | <p>but less than 18 months, since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 36 months, but less than 39 months, since the last active assessment on one of its applicable BES</p> | <p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 39 months, but less than 42 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p> | <p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 42 months, but less than 45 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p> | <p>vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 24 months since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 45 months since the last active</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |          |  |
|-----|--------------|-----|--|--------------|----------|--|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL   |
|     |              |     | Cyber Systems.<br>(3.2)                  |              |          | assessment on one of its applicable BES Cyber Systems.(3.2)<br>OR<br>The Responsible Entity has implemented and documented one or more vulnerability assessment processes for each of its applicable BES Cyber Systems, but did not perform the active vulnerability assessment in a manner that models an existing baseline configuration of its applicable BES Cyber Systems. (3.3)<br>OR<br>The Responsible Entity has implemented one or more documented |



| R # | Time Horizon | VRF | Violation Severity Levels (CIP-010-1(X)) |              |          |   |
|-----|--------------|-----|--|--------------|----------|---|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL | Severe VSL  |
|     |              |     |  |              |          | vulnerability assessment processes for each of its applicable BES Cyber Systems, but has not documented the results of the vulnerability assessments, the action plans to remediate or mitigate vulnerabilities identified in the assessments, the planned date of completion of the action plan, and the execution status of the mitigation plans. (3.4) |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### Requirement R1:

##### Baseline Configuration

The concept of establishing a Cyber Asset’s baseline configuration is meant to provide clarity on requirement language found in previous CIP standard versions. Modification of any item within an applicable Cyber Asset’s baseline configuration provides the triggering mechanism for when entities must apply change management processes.

Baseline configurations in CIP-010 consist of five different items: Operating system/firmware, commercially available software or open-source application software, custom software, logical network accessible port identification, and security patches. Operating system information identifies the software and version that is in use on the Cyber Asset. In cases where an independent operating system does not exist (such as for a protective relay), then firmware information should be identified. Commercially available or open-source application software identifies applications that were intentionally installed on the cyber asset. The use of the term “intentional” was meant to ensure that only software applications that were determined to be necessary for Cyber Asset use should be included in the baseline configuration. The SDT does not intend for notepad, calculator, DLL, device drivers, or other applications included in an operating system package as commercially available or open-source application software to be

included. Custom software installed may include scripts developed for local entity functions or other custom software developed for a specific task or function for the entity's use. If additional software was intentionally installed and is not commercially available or open-source, then this software could be considered custom software. If a specific device needs to communicate with another device outside the network, communications need to be limited to only the devices that need to communicate per the requirement in CIP-007-5(X). Those ports which are accessible need to be included in the baseline. Security patches applied would include all historical and current patches that have been applied on the cyber asset. While CIP-007-5(X) R2.1 requires entities to track, evaluate, and install security patches, CIP-010 R1.1.5 requires entities to list all applied historical and current patches.

Further guidance can be understood with the following example that details the baseline configuration for a serial-only microprocessor relay:

### Asset #051028 at Substation Alpha

- R1.1.1 – Firmware: [MANUFACTURER]-[MODEL]-XYZ-1234567890-ABC
- R1.1.2 – Not Applicable
- R1.1.3 – Not Applicable
- R1.1.4 – Not Applicable
- R1.1.5 – Patch 12345, Patch 67890, Patch 34567, Patch 437823

Also, for a typical IT system, the baseline configuration could reference an IT standard that includes configuration details. An entity would be expected to provide that IT standard as part of their compliance evidence.

## Cyber Security Controls

The use of cyber security controls refers specifically to controls referenced and applied according to CIP-005 and CIP-007. The concept presented in the relevant requirement sub-parts in CIP-010 R1 is that an entity is to identify/verify controls from CIP-005 and CIP-007 that could be impacted for a change that deviates from the existing baseline configuration. The SDT does not intend for Responsible Entities to identify/verify all controls located within CIP-005 and CIP-007 for each change. The Responsible Entity is only to identify/verify those control(s) that could be affected by the baseline configuration change. For example, changes that affect logical network ports would only involve CIP-007 R1 (Ports and Services), while changes that affect security patches would only involve CIP-007 R2 (Security Patch Management). The SDT chose not to identify the specific requirements from CIP-005 and CIP-007 in CIP-010 language as the intent of the related requirements is to be able to identify/verify any of the controls in those standards that are affected as a result of a change to the baseline configuration. The SDT believes it possible that all requirements from CIP-005 and CIP-007 may be identified for a

major change to the baseline configuration, and therefore, CIP-005 and CIP-007 was cited at the standard-level versus the requirement-level.

### **Test Environment**

The Control Center test environment (or production environment where the test is performed in a manner that minimizes adverse effects) should model the baseline configuration, but may have a different set of components. For instance, an entity may have a BES Cyber System that runs a database on one component and a web server on another component. The test environment may have the same operating system, security patches, network accessible ports, and software, but have both the database and web server running on a single component instead of multiple components.

Additionally, the Responsible Entity should note that wherever a test environment (or production environment where the test is performed in a manner that minimizes adverse effects) is mentioned, the requirement is to “model” the baseline configuration and not duplicate it exactly. This language was chosen deliberately in order to allow for individual elements of a BES Cyber System at a Control Center to be modeled that may not otherwise be able to be replicated or duplicated exactly; such as, but not limited to, a legacy map-board controller or the numerous data communication links from the field or to other Control Centers (such as by ICCP).

### **Requirement R2:**

The SDT’s intent of R2 is to require automated monitoring of the BES Cyber System. However, the SDT understands that there may be some Cyber Assets where automated monitoring may not be possible (such as a GPS time clock). For that reason, automated technical monitoring was not explicitly required, and a Responsible Entity may choose to accomplish this requirement through manual procedural controls.

### **Requirement R3:**

The Responsible Entity should note that the requirement provides a distinction between paper and active vulnerability assessments. The justification for this distinction is well-documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking. In developing their vulnerability assessment processes, Responsible Entities are strongly encouraged to include at least the following elements, several of which are referenced in CIP-005 and CIP-007:

Paper Vulnerability Assessment:

1. Network Discovery - A review of network connectivity to identify all Electronic Access Points to the Electronic Security Perimeter.
2. Network Port and Service Identification - A review to verify that all enabled ports and services have an appropriate business justification.

3. Vulnerability Review - A review of security rule-sets and configurations including controls for default accounts, passwords, and network management community strings.
4. Wireless Review - Identification of common types of wireless networks (such as 802.11a/b/g/n) and a review of their controls if they are in any way used for BES Cyber System communications.

### Active Vulnerability Assessment:

1. Network Discovery - Use of active discovery tools to discover active devices and identify communication paths in order to verify that the discovered network architecture matches the documented architecture.
2. Network Port and Service Identification – Use of active discovery tools (such as Nmap) to discover open ports and services.
3. Vulnerability Scanning – Use of a vulnerability scanning tool to identify network accessible ports and services along with the identification of known vulnerabilities associated with services running on those ports.
4. Wireless Scanning – Use of a wireless scanning tool to discover wireless signals and networks in the physical perimeter of a BES Cyber System. Serves to identify unauthorized wireless devices within the range of the wireless scanning tool.

In addition, Responsible Entities are strongly encouraged to review NIST SP800-115 for additional guidance on how to conduct a vulnerability assessment.

### **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

#### **Rationale for R1:**

The configuration change management processes are intended to prevent unauthorized modifications to BES Cyber Systems.

**Reference to prior version:** (Part 1.1) New Requirement

**Change Rationale:** (Part 1.1)

*The baseline configuration requirement was incorporated from the DHS Catalog for Control Systems Security. The baseline requirement is also intended to clarify precisely when a change management process must be invoked and which elements of the configuration must be examined.*

**Reference to prior version:** (Part 1.2) CIP-007-3, R9; CIP-003-3, R6

**Change Rationale:** (Part 1.2)

*The SDT added requirement to explicitly authorize changes. This requirement was previously implied by CIP-003-3, Requirement R6.*

**Reference to prior version:** (Part 1.3) CIP-007-3, R9; CIP-005-3, R5

**Change Rationale:** (Part 1.3)

*Document maintenance requirement due to a BES Cyber System change is equivalent to the requirements in the previous versions of the standard.*

**Reference to prior version:** (Part 1.4) CIP-007-3, R1

**Change Rationale:** (Part 1.4)

*The SDT attempted to provide clarity on when testing must occur and removed requirement for specific test procedures because it is implicit in the performance of the requirement.*

**Reference to prior version:** (Part 1.5) CIP-007-3, R1

**Change Rationale:** (Part 1.5)

*This requirement provides clarity on when testing must occur and requires additional testing to ensure that accidental consequences of planned changes are appropriately managed.*

*This change addresses FERC Order No. 706, Paragraphs 397, 609, 610, and 611.*

**Rationale for R2:**

The configuration monitoring processes are intended to detect unauthorized modifications to BES Cyber Systems.

**Reference to prior version:** (Part 2.1) New Requirement

**Change Rationale:** (Part 2.1)

*The monitoring of the configuration of the BES Cyber System provides an express acknowledgement of the need to consider malicious actions along with intentional changes.*

*This requirement was added after review of the DHS Catalog of Control System Security and to address FERC Order No. 706, Paragraph 397.*

*Thirty-five Calendar days allows for a “once-a-month” frequency with slight flexibility to account for months with 31 days or for beginning or endings of months on weekends.*

**Rationale for R3:**

The vulnerability assessment processes are intended to act as a component in an overall program to periodically ensure the proper implementation of cyber security controls as well as to continually improve the security posture of BES Cyber Systems.

The vulnerability assessment performed for this requirement may be a component of deficiency identification, assessment, and correction.

**Reference to prior version:** (Part 3.1) CIP-005-4, R4; CIP-007-4, R8

**Change Rationale:** (Part 3.1)

*As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.*

**Reference to prior version:** (Part 3.2) New Requirement

**Change Rationale:** (Part 3.2)

*FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.*

*As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.*

**Reference to prior version:** (Part 3.3) New Requirement

**Change Rationale:** (Part 3.3)

*FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.*

**Reference to prior version:** (Part 3.4) CIP-005-3, R4.5; CIP-007-3, R8.4

**Change Rationale:** (Part 3.4)

*Added a requirement for an entity planned date of completion as per the directive in FERC Order No. 706, Paragraph 643.*

### Version History

| Version | Date     | Action  | Change Tracking  |
|---------|----------|---|--|
| 1       | 11/26/12 | Adopted by the NERC Board of Trustees.                                      | Developed to define the configuration change management and vulnerability assessment requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706. |
| 1       | 11/22/13 | FERC Order issued approving CIP-010-1. (Order becomes effective on 2/3/14.) |  |



Guidelines and Technical Basis

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|             |            |  |   |
|-------------|------------|--|---|
| <u>1(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |
|-------------|------------|--|---|

## A. Introduction

1. **Title:** Cyber Security — Information Protection
2. **Number:** CIP-011-1(X)
3. **Purpose:** To prevent unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**

**4.1.7 Transmission Operator**

**4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-011-1(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-011-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-011-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-011-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies**, . . .

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies,

assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

#### **"Applicable Systems" Columns in Tables:**

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact

and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)**– Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System

## B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M1.** Evidence for the information protection program must include the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-011-1(X) Table R1 – Information Protection |   |   |   |
|--|---|---|---|
| Part   | Applicable Systems  | Requirements  | Measures  |
| 1.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Method(s) to identify information that meets the definition of BES Cyber System Information.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Documented method to identify BES Cyber System Information from entity’s information protection program; or</li> <li>• Indications on information (e.g., labels or classification) that identify BES Cyber System Information as designated in the entity’s information protection program; or</li> <li>• Training materials that provide personnel with sufficient knowledge to recognize BES Cyber System Information; or</li> <li>• Repository or electronic and physical location designated for housing BES Cyber System Information in the entity’s information protection program.</li> </ul> |
|  |   |   |   |



| CIP-011-1(X) Table R1 – Information Protection |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirement   | Measure  |
| 1.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Procedure(s) for protecting and securely handling BES Cyber System Information, including storage, transit, and use.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Procedures for protecting and securely handling, which include topics such as storage, security during transit, and use of BES Cyber System Information; or</li> <li>• Records indicating that BES Cyber System Information is handled in a manner consistent with the entity’s documented procedure(s).</li> </ul> |

- R2.** Each Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirements  | Measures   |
| 2.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Prior to the release for reuse of applicable Cyber Assets that contain BES Cyber System Information (except for reuse within other systems identified in the “Applicable Systems” column), the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records tracking sanitization actions taken to prevent unauthorized retrieval of BES Cyber System Information such as clearing, purging, or destroying; or</li> <li>• Records tracking actions such as encrypting, retaining in the Physical Security Perimeter or other methods used to prevent unauthorized retrieval of BES Cyber System Information.</li> </ul> |

| CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirements  | Measures   |
| 2.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Prior to the disposal of applicable Cyber Assets that contain BES Cyber System Information, the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset or destroy the data storage media.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records that indicate that data storage media was destroyed prior to the disposal of an applicable Cyber Asset; or</li> <li>• Records of actions taken to prevent unauthorized retrieval of BES Cyber System Information prior to the disposal of an applicable Cyber Asset.</li> </ul> |

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon        | VRF    | Violation Severity Levels (CIP-011-1(X)) |              |   |   |
|-----|---------------------|--------|--|--------------|---|---|
|     |                     |        | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
| R1  | Operations Planning | Medium | N/A                                      |              | <p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information but did not identify,</p> | <p>The Responsible Entity has not documented or implemented a BES Cyber System Information protection program (R1).</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-011-1(X)) |              |  |            |
|-----|--------------|-----|--|--------------|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL |
|     |              |     |  |              | assess, or correct the deficiencies. (1.1)<br>OR<br>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.2)<br>OR<br>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information |            |

| R #       | Time Horizon               | VRF          | Violation Severity Levels (CIP-011-1(X)) |  |   |   |
|-----------|----------------------------|--------------|--|--|---|---|
|           |                            |              | Lower VSL                                | Moderate VSL   | High VSL  | Severe VSL  |
|           |                            |              |  |  | but did not identify, assess, or correct the deficiencies. (1.2)  |   |
| <b>R2</b> | <b>Operations Planning</b> | <b>Lower</b> | N/A                                      | The Responsible Entity implemented one or more documented processes but did not include processes for reuse as to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.1) | The Responsible Entity implemented one or more documented processes but did not include disposal or media destruction processes to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.2) | The Responsible Entity has not documented or implemented any processes for applicable requirement parts in CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal. (R2) |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.



## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)'s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### **Requirement R1:**

Responsible Entities are free to utilize existing change management and asset management systems. However, the information contained within those systems must be evaluated, as the information protection requirements still apply.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

This requirement mandates that BES Cyber System Information be identified. The Responsible Entity has flexibility in determining how to implement the requirement. The Responsible Entity should explain the method for identifying the BES Cyber System Information in their information protection program. For example, the Responsible Entity may decide to mark or label the documents. Identifying separate classifications of BES Cyber System Information is not specifically required. However, a Responsible Entity maintains the flexibility to do so if they desire. As long as the Responsible Entity's information protection program includes all applicable items, additional classification levels (e.g., confidential, public, internal use only, etc.) can be created that go above and beyond the requirements. If the entity chooses to use classifications, then the types of classifications used by the entity and any associated labeling should be documented in the entity's BES Cyber System Information Program.

The Responsible Entity may store all of the information about BES Cyber Systems in a separate repository or location (physical and/or electronic) with access control implemented. For example, the Responsible Entity's program could document that all information stored in an identified repository is considered BES Cyber System Information, the program may state that all information contained in an identified section of a specific repository is considered BES Cyber System Information, or the program may document that all hard copies of information are stored in a secured area of the building. Additional methods for implementing the requirement are suggested in the measures section. However, the methods listed in measures are not meant to be an exhaustive list of methods that the entity may choose to utilize for the identification of BES Cyber System Information.

The SDT does not intend that this requirement cover publicly available information, such as vendor manuals that are available via public websites or information that is deemed to be publicly releasable.

Information protection pertains to both digital and hardcopy information. R1.2 requires one or more procedures for the protection and secure handling BES Cyber System Information, including storage, transit, and use.

The entity's written Information Protection Program should explain how the entity handles aspects of information protection including specifying how BES Cyber System Information is to be securely handled during transit in order to protect against unauthorized access, misuse, or corruption and to protect confidentiality of the communicated BES Cyber System Information. For example, the use of a third-party communication service provider instead of organization-owned infrastructure may warrant the use of encryption to prevent unauthorized disclosure of information during transmission. The entity may choose to establish a trusted communications path for transit of BES Cyber System Information. The trusted communications path would utilize a logon or other security measures to provide secure handling during transit. The entity may employ alternative physical protective measures, such as the use of a courier or locked container for transmission of information. It is not the intent of this standard to mandate the use of one particular format for secure handling during transit.

A good Information Protection Program will document the circumstances under which BES Cyber System Information can be shared with or used by third parties. The organization should distribute or share information on a need-to-know basis. For example, the entity may specify that a confidentiality agreement, non-disclosure arrangement, contract, or written agreement of some kind concerning the handling of information must be in place between the entity and the third party. The entity's Information Protection Program should specify circumstances for sharing of BES Cyber System Information with and use by third parties, for example, use of a non-disclosure agreement. The entity should then follow their documented program. These requirements do not mandate one specific type of arrangement.

### **Requirement R2:**

This requirement allows for BES Cyber Systems to be removed from service and analyzed with their media intact, as that should not constitute a release for reuse. However, following the

analysis, if the media is to be reused outside of a BES Cyber System or disposed of, the entity must take action to prevent the unauthorized retrieval of BES Cyber System Information from the media.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

If an applicable Cyber Asset is removed from the Physical Security Perimeter prior to action taken to prevent the unauthorized retrieval of BES Cyber System Information or destroying the data storage media, the responsible entity should maintain documentation that identifies the custodian for the data storage media while the data storage media is outside of the Physical Security Perimeter prior to actions taken by the entity as required in R2.

Media sanitization is the process used to remove information from system media such that reasonable assurance exists that the information cannot be retrieved or reconstructed. Media sanitization is generally classified into four categories: Disposal, clearing, purging, and destroying. For the purposes of this requirement, disposal by itself, with the exception of certain special circumstances, such as the use of strong encryption on a drive used in a SAN or other media, should never be considered acceptable. The use of clearing techniques may provide a suitable method of sanitization for media that is to be reused, whereas purging techniques may be more appropriate for media that is ready for disposal.

The following information from NIST SP800-88 provides additional guidance concerning the types of actions that an entity might take to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media:

**Clear:** One method to sanitize media is to use software or hardware products to overwrite storage space on the media with non-sensitive data. This process may include overwriting not only the logical storage location of a file(s) (e.g., file allocation table) but also may include all addressable locations. The security goal of the overwriting process is to replace written data with random data. Overwriting cannot be used for media that are damaged or not rewriteable. The media type and size may also influence whether overwriting is a suitable sanitization method [SP 800-36].

**Purge:** Degaussing and executing the firmware Secure Erase command (for ATA drives only) are acceptable methods for purging. Degaussing is exposing the magnetic media to a strong magnetic field in order to disrupt the recorded magnetic domains. A degausser is a device that generates a magnetic field used to sanitize magnetic media. Degaussers are rated based on the type (i.e., low energy or high energy) of magnetic media they can purge. Degaussers operate using either a strong permanent magnet or an electromagnetic coil. Degaussing can be an effective method for purging damaged or inoperative media, for purging media with exceptionally large storage capacities, or for quickly purging diskettes. [SP 800-36] Executing the firmware Secure Erase command (for ATA drives only) and degaussing are examples of acceptable methods for purging.

Degaussing of any hard drive assembly usually destroys the drive as the firmware that manages the device is also destroyed.

**Destroy:** There are many different types, techniques, and procedures for media destruction. Disintegration, Pulverization, Melting, and Incineration are sanitization methods designed to completely destroy the media. They are typically carried out at an outsourced metal destruction or licensed incineration facility with the specific capabilities to perform these activities effectively, securely, and safely. Optical mass storage media, including compact disks (CD, CD-RW, CD-R, CD-ROM), optical disks (DVD), and MO disks, must be destroyed by pulverizing, crosscut shredding or burning. In some cases such as networking equipment, it may be necessary to contact the manufacturer for proper sanitization procedure.

It is critical that an organization maintain a record of its sanitization actions to prevent unauthorized retrieval of BES Cyber System Information. Entities are strongly encouraged to review NIST SP800-88 for guidance on how to develop acceptable media sanitization processes.

### **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

#### **Rationale for R1:**

The SDT's intent of the information protection program is to prevent unauthorized access to BES Cyber System Information.

**Summary of Changes:** CIP 003-4 R4, R4.2, and R 4.3 have been moved to CIP 011 R1. CIP-003-4, Requirement R4.1 was moved to the definition of BES Cyber System Information.

**Reference to prior version:** (Part 1.1) CIP-003-3, R4; CIP-003-3, R4.2

**Change Rationale:** (Part 1.1)

*The SDT removed the explicit requirement for classification as there was no requirement to have multiple levels of protection (e.g., confidential, public, internal use only, etc.) This modification does not prevent having multiple levels of classification, allowing more flexibility for entities to incorporate the CIP information protection program into their normal business.*

**Reference to prior version:** (Part 1.2) CIP-003-3, R4

**Change Rationale:** (Part 1.2)

*The SDT changed the language from “protect” information to “Procedures for protecting and securely handling” to clarify the protection that is required.*

**Rationale for R2:**

The intent of the BES Cyber Asset reuse and disposal process is to prevent the unauthorized dissemination of BES Cyber System Information upon reuse or disposal.

**Reference to prior version:** (Part 2.1) CIP-007-3, R7.2

**Change Rationale:** (Part 2.1)

*Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.*

**Reference to prior version:** (Part 2.2) CIP-007-3, R7.1

**Change Rationale:** (Part 2.2)

*Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.*

*The SDT also removed the requirement explicitly requiring records of destruction/redeployment as this was seen as demonstration of the existing requirement and not a requirement in and of itself.*

## Version History

| Version | Date     | Action  | Change Tracking  |
|---------|----------|---|--|
| 1       | 11/26/12 | Adopted by the NERC Board of Trustees.                                      | Developed to define the information protection requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706. |
| 1       | 11/22/13 | FERC Order issued approving CIP-011-1. (Order becomes effective on 2/3/14.) |  |
| 1(X)    | TBD      | Adopted by the NERC Board of Trustees                                       | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS   |

## A. Introduction

1. **Title:** Cyber Security — Information Protection
2. **Number:** CIP-011-1(X)
3. **Purpose:** To prevent unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
    - 4.1.1 **Balancing Authority**
    - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
      - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
        - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
        - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
      - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
      - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
    - 4.1.3 **Generator Operator**
    - 4.1.4 **Generator Owner**
    - 4.1.5 **Interchange Coordinator or Interchange Authority**
    - 4.1.6 **Reliability Coordinator**

**4.1.7 Transmission Operator**

**4.1.8 Transmission Owner**

**4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1** Each UFLS or UVLS System that:

**4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2** Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**

All BES Facilities.

**4.2.3 Exemptions:** The following are exempt from Standard CIP-011-1(X):

**4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

**4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.



**4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

**5. Effective Dates:**

1. **24 Months Minimum** – CIP-011-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.

2. In those jurisdictions where no regulatory approval is required, CIP-011-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

**6. Background:**

Standard CIP-011-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement's common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements.

An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

**“Applicable Systems” Columns in Tables:**

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept

from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)**– Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System

## B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M1.** Evidence for the information protection program must include the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-011-1(X) Table R1 – Information Protection

| Part | Applicable Systems  | Requirements  | Measures  |
|------|---|---|---|
| 1.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Method(s) to identify information that meets the definition of BES Cyber System Information.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Documented method to identify BES Cyber System Information from entity’s information protection program; or</li> <li>• Indications on information (e.g., labels or classification) that identify BES Cyber System Information as designated in the entity’s information protection program; or</li> <li>• Training materials that provide personnel with sufficient knowledge to recognize BES Cyber System Information; or</li> <li>• Repository or electronic and physical location designated for housing BES Cyber System Information in the entity’s information protection program.</li> </ul> |
|      |   |   |   |

| CIP-011-1(X) Table R1 – Information Protection |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirement   | Measure  |
| 1.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS; and</li> <li>2. PACS</li> </ol> | <p>Procedure(s) for protecting and securely handling BES Cyber System Information, including storage, transit, and use.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Procedures for protecting and securely handling, which include topics such as storage, security during transit, and use of BES Cyber System Information; or</li> <li>• Records indicating that BES Cyber System Information is handled in a manner consistent with the entity’s documented procedure(s).</li> </ul> |

- R2.** Each Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal* and additional evidence to demonstrate implementation as described in the Measures column of the table.

| CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirements  | Measures   |
| 2.1  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Prior to the release for reuse of applicable Cyber Assets that contain BES Cyber System Information (except for reuse within other systems identified in the “Applicable Systems” column), the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records tracking sanitization actions taken to prevent unauthorized retrieval of BES Cyber System Information such as clearing, purging, or destroying; or</li> <li>• Records tracking actions such as encrypting, retaining in the Physical Security Perimeter or other methods used to prevent unauthorized retrieval of BES Cyber System Information.</li> </ul> |

| CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal |   |   |  |
|--|---|---|--|
| Part   | Applicable Systems  | Requirements  | Measures   |
| 2.2  | <p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> <li>1. EACMS;</li> <li>2. PACS; and</li> <li>3. PCA</li> </ol> | <p>Prior to the disposal of applicable Cyber Assets that contain BES Cyber System Information, the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset or destroy the data storage media.</p> | <p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> <li>• Records that indicate that data storage media was destroyed prior to the disposal of an applicable Cyber Asset; or</li> <li>• Records of actions taken to prevent unauthorized retrieval of BES Cyber System Information prior to the disposal of an applicable Cyber Asset.</li> </ul> |



## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

#### 1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### 1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

| R # | Time Horizon        | VRF    | Violation Severity Levels (CIP-011-1(X)) |              |   |   |
|-----|---------------------|--------|--|--------------|---|---|
|     |                     |        | Lower VSL                                | Moderate VSL | High VSL  | Severe VSL  |
| R1  | Operations Planning | Medium | N/A                                      |              | <p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information but did not identify,</p> | <p>The Responsible Entity has not documented or implemented a BES Cyber System Information protection program (R1).</p> |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-011-1(X)) |              |  |            |
|-----|--------------|-----|--|--------------|--|------------|
|     |              |     | Lower VSL                                | Moderate VSL | High VSL   | Severe VSL |
|     |              |     |  |              | assess, or correct the deficiencies. (1.1)<br>OR<br>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.2)<br>OR<br>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information |            |

| R # | Time Horizon        | VRF   | Violation Severity Levels (CIP-011-1(X)) |  |   |   |
|-----|---------------------|-------|--|--|---|---|
|     |                     |       | Lower VSL                                | Moderate VSL   | High VSL  | Severe VSL  |
|     |                     |       |  |  | but did not identify, assess, or correct the deficiencies. (1.2)  |   |
| R2  | Operations Planning | Lower | N/A                                      | The Responsible Entity implemented one or more documented processes but did not include processes for reuse as to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.1) | The Responsible Entity implemented one or more documented processes but did not include disposal or media destruction processes to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.2) | The Responsible Entity has not documented or implemented any processes for applicable requirement parts in CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal. (R2) |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

None.

## Guidelines and Technical Basis

### Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)'s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

#### **Requirement R1:**

Responsible Entities are free to utilize existing change management and asset management systems. However, the information contained within those systems must be evaluated, as the information protection requirements still apply.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

This requirement mandates that BES Cyber System Information be identified. The Responsible Entity has flexibility in determining how to implement the requirement. The Responsible Entity should explain the method for identifying the BES Cyber System Information in their information protection program. For example, the Responsible Entity may decide to mark or label the documents. Identifying separate classifications of BES Cyber System Information is not specifically required. However, a Responsible Entity maintains the flexibility to do so if they desire. As long as the Responsible Entity's information protection program includes all applicable items, additional classification levels (e.g., confidential, public, internal use only, etc.) can be created that go above and beyond the requirements. If the entity chooses to use classifications, then the types of classifications used by the entity and any associated labeling should be documented in the entity's BES Cyber System Information Program.

The Responsible Entity may store all of the information about BES Cyber Systems in a separate repository or location (physical and/or electronic) with access control implemented. For example, the Responsible Entity's program could document that all information stored in an identified repository is considered BES Cyber System Information, the program may state that all information contained in an identified section of a specific repository is considered BES Cyber System Information, or the program may document that all hard copies of information are stored in a secured area of the building. Additional methods for implementing the requirement are suggested in the measures section. However, the methods listed in measures are not meant to be an exhaustive list of methods that the entity may choose to utilize for the identification of BES Cyber System Information.

The SDT does not intend that this requirement cover publicly available information, such as vendor manuals that are available via public websites or information that is deemed to be publicly releasable.

Information protection pertains to both digital and hardcopy information. R1.2 requires one or more procedures for the protection and secure handling BES Cyber System Information, including storage, transit, and use.

The entity's written Information Protection Program should explain how the entity handles aspects of information protection including specifying how BES Cyber System Information is to be securely handled during transit in order to protect against unauthorized access, misuse, or corruption and to protect confidentiality of the communicated BES Cyber System Information. For example, the use of a third-party communication service provider instead of organization-owned infrastructure may warrant the use of encryption to prevent unauthorized disclosure of information during transmission. The entity may choose to establish a trusted communications path for transit of BES Cyber System Information. The trusted communications path would utilize a logon or other security measures to provide secure handling during transit. The entity may employ alternative physical protective measures, such as the use of a courier or locked container for transmission of information. It is not the intent of this standard to mandate the use of one particular format for secure handling during transit.

A good Information Protection Program will document the circumstances under which BES Cyber System Information can be shared with or used by third parties. The organization should distribute or share information on a need-to-know basis. For example, the entity may specify that a confidentiality agreement, non-disclosure arrangement, contract, or written agreement of some kind concerning the handling of information must be in place between the entity and the third party. The entity's Information Protection Program should specify circumstances for sharing of BES Cyber System Information with and use by third parties, for example, use of a non-disclosure agreement. The entity should then follow their documented program. These requirements do not mandate one specific type of arrangement.

### **Requirement R2:**

This requirement allows for BES Cyber Systems to be removed from service and analyzed with their media intact, as that should not constitute a release for reuse. However, following the

analysis, if the media is to be reused outside of a BES Cyber System or disposed of, the entity must take action to prevent the unauthorized retrieval of BES Cyber System Information from the media.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

If an applicable Cyber Asset is removed from the Physical Security Perimeter prior to action taken to prevent the unauthorized retrieval of BES Cyber System Information or destroying the data storage media, the responsible entity should maintain documentation that identifies the custodian for the data storage media while the data storage media is outside of the Physical Security Perimeter prior to actions taken by the entity as required in R2.

Media sanitization is the process used to remove information from system media such that reasonable assurance exists that the information cannot be retrieved or reconstructed. Media sanitization is generally classified into four categories: Disposal, clearing, purging, and destroying. For the purposes of this requirement, disposal by itself, with the exception of certain special circumstances, such as the use of strong encryption on a drive used in a SAN or other media, should never be considered acceptable. The use of clearing techniques may provide a suitable method of sanitization for media that is to be reused, whereas purging techniques may be more appropriate for media that is ready for disposal.

The following information from NIST SP800-88 provides additional guidance concerning the types of actions that an entity might take to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media:

**Clear:** One method to sanitize media is to use software or hardware products to overwrite storage space on the media with non-sensitive data. This process may include overwriting not only the logical storage location of a file(s) (e.g., file allocation table) but also may include all addressable locations. The security goal of the overwriting process is to replace written data with random data. Overwriting cannot be used for media that are damaged or not rewriteable. The media type and size may also influence whether overwriting is a suitable sanitization method [SP 800-36].

**Purge:** Degaussing and executing the firmware Secure Erase command (for ATA drives only) are acceptable methods for purging. Degaussing is exposing the magnetic media to a strong magnetic field in order to disrupt the recorded magnetic domains. A degausser is a device that generates a magnetic field used to sanitize magnetic media. Degaussers are rated based on the type (i.e., low energy or high energy) of magnetic media they can purge. Degaussers operate using either a strong permanent magnet or an electromagnetic coil. Degaussing can be an effective method for purging damaged or inoperative media, for purging media with exceptionally large storage capacities, or for quickly purging diskettes. [SP 800-36] Executing the firmware Secure Erase command (for ATA drives only) and degaussing are examples of acceptable methods for purging.



Degaussing of any hard drive assembly usually destroys the drive as the firmware that manages the device is also destroyed.

**Destroy:** There are many different types, techniques, and procedures for media destruction. Disintegration, Pulverization, Melting, and Incineration are sanitization methods designed to completely destroy the media. They are typically carried out at an outsourced metal destruction or licensed incineration facility with the specific capabilities to perform these activities effectively, securely, and safely. Optical mass storage media, including compact disks (CD, CD-RW, CD-R, CD-ROM), optical disks (DVD), and MO disks, must be destroyed by pulverizing, crosscut shredding or burning. In some cases such as networking equipment, it may be necessary to contact the manufacturer for proper sanitization procedure.

It is critical that an organization maintain a record of its sanitization actions to prevent unauthorized retrieval of BES Cyber System Information. Entities are strongly encouraged to review NIST SP800-88 for guidance on how to develop acceptable media sanitization processes.

### **Rationale:**

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

#### **Rationale for R1:**

The SDT's intent of the information protection program is to prevent unauthorized access to BES Cyber System Information.

**Summary of Changes:** CIP 003-4 R4, R4.2, and R 4.3 have been moved to CIP 011 R1. CIP-003-4, Requirement R4.1 was moved to the definition of BES Cyber System Information.

**Reference to prior version:** (Part 1.1) CIP-003-3, R4; CIP-003-3, R4.2

**Change Rationale:** (Part 1.1)

*The SDT removed the explicit requirement for classification as there was no requirement to have multiple levels of protection (e.g., confidential, public, internal use only, etc.) This modification does not prevent having multiple levels of classification, allowing more flexibility for entities to incorporate the CIP information protection program into their normal business.*

**Reference to prior version:** (Part 1.2) CIP-003-3, R4

**Change Rationale:** (Part 1.2)

*The SDT changed the language from “protect” information to “Procedures for protecting and securely handling” to clarify the protection that is required.*

**Rationale for R2:**

The intent of the BES Cyber Asset reuse and disposal process is to prevent the unauthorized dissemination of BES Cyber System Information upon reuse or disposal.

**Reference to prior version:** (Part 2.1) CIP-007-3, R7.2

**Change Rationale:** (Part 2.1)

*Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.*

**Reference to prior version:** (Part 2.2) CIP-007-3, R7.1

**Change Rationale:** (Part 2.2)

*Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.*

*The SDT also removed the requirement explicitly requiring records of destruction/redeployment as this was seen as demonstration of the existing requirement and not a requirement in and of itself.*

## Version History

| Version     | Date       | Action  | Change Tracking  |
|-------------|------------|---|--|
| 1           | 11/26/12   | Adopted by the NERC Board of Trustees.                                      | Developed to define the information protection requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706. |
| 1           | 11/22/13   | FERC Order issued approving CIP-011-1. (Order becomes effective on 2/3/14.) |  |
| <u>1(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>                                | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>  |

### A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2(X)
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider

### 5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

### 6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2(X) Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
  
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2(X) Attachment 1 and in accordance with the entity responsible for reporting.
  
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
  
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2(X) Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*]  
[*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

## **C. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1 Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### **1.2 Evidence Retention**

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

**1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br><br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |



| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)

**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |

**EOP-004-2(X) — Event Reporting**

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq$ 100 MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq$ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm$ 10% of nominal voltage sustained for $\geq$ 15 continuous minutes.   |

**EOP-004-2(X) — Event Reporting**

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |

**EOP-004-2(X) — Event Reporting**

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| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |

EOP-004 - Attachment 2: Event Reporting Form

| <b>EOP-004 Attachment 2: Event Reporting Form</b>   |   |
|---|---|
| <p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a> , Facsimile 404-446-9770 or voice: 404-446-9780.</p> |   |
| Task  | Comments  |
| 1.  | <p>Entity filing the report include:<br/>                     Company name:<br/>                     Name of contact person:<br/>                     Email address of contact person:<br/>                     Telephone Number:<br/>                     Submitted by (name):</p>   |
| 2.  | <p>Date and Time of recognized event.<br/>                     Date: (mm/dd/yyyy)<br/>                     Time: (hh:mm)<br/>                     Time/Zone:</p>  |
| 3.  | <p>Did the event originate in your system?      Yes <input type="checkbox"/>    No <input type="checkbox"/>    Unknown <input type="checkbox"/></p>   |
| 4.  | <p style="text-align: center;"><b>Event Identification and Description:</b></p> <p>(Check applicable box)</p> <p><input type="checkbox"/> Damage or destruction of a Facility</p> <p><input type="checkbox"/> Physical Threat to a Facility</p> <p><input type="checkbox"/> Physical Threat to a control center</p> <p><input type="checkbox"/> BES Emergency:</p> <p style="padding-left: 20px;"><input type="checkbox"/> public appeal for load reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> system-wide voltage reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> manual firm load shedding</p> <p style="padding-left: 20px;"><input type="checkbox"/> automatic firm load shedding</p> <p><input type="checkbox"/> Voltage deviation on a Facility</p> <p><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)</p> <p><input type="checkbox"/> Loss of firm load</p> <p><input type="checkbox"/> System separation</p> <p><input type="checkbox"/> Generation loss</p> <p><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)</p> <p><input type="checkbox"/> Transmission loss</p> <p><input type="checkbox"/> unplanned control center evacuation</p> <p><input type="checkbox"/> Complete loss of voice communication capability</p> <p><input type="checkbox"/> Complete loss of monitoring capability</p> <p>Written description (optional):</p> |

### Guideline and Technical Basis

#### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

#### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

#### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to



## **EOP-004-2(X) — Event Reporting**

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reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### **Data Gathering**

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2(X) specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2(X) may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### **Law Enforcement Reporting**

The reliability objective of EOP-004-2(X) is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### **Stakeholders in the Reporting Process**

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

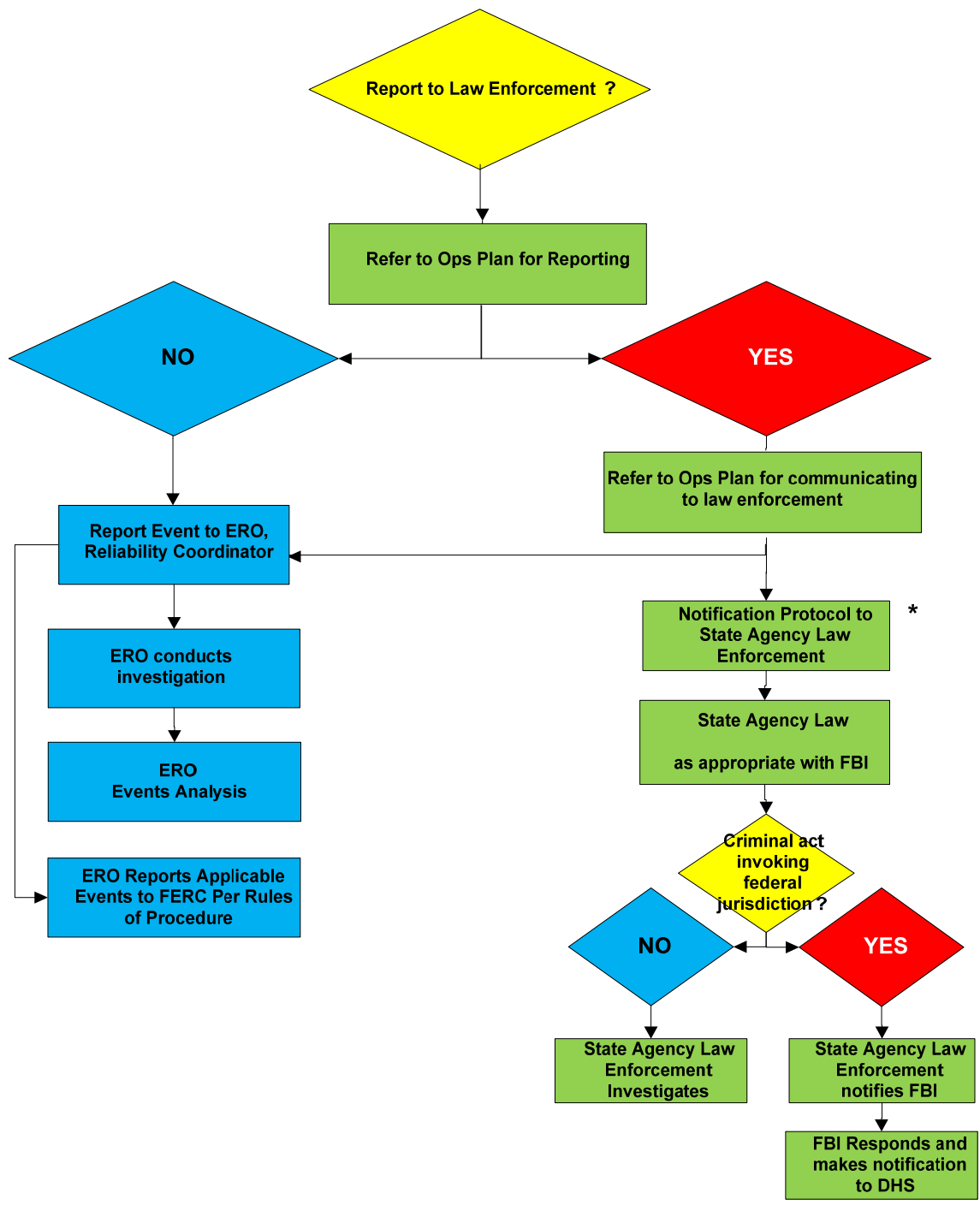
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

### Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

#### Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

#### Summary of Concepts and Assumptions:

##### *The Standard:*

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

##### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### **Discussion of Event Reporting**

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### ***What about sabotage?***

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2(X) Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.



## Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 2       |                  | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)  |
| 2       | November 7, 2012 | Adopted by the NERC Board of Trustees  |  |
| 2       | June 20, 2013    | FERC approved  |  |
| 2(X)    | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2(X)
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider

### 5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

### 6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2(X) Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2(X) Attachment 1 and in accordance with the entity responsible for reporting.
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2(X) Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

**1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br><br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |

| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)



**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |

EOP-004-2(X) — Event Reporting

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq$ 100 MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq$ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <del>SPS</del> /RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm$ 10% of nominal voltage sustained for $\geq$ 15 continuous minutes.   |

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |

| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |

EOP-004 - Attachment 2: Event Reporting Form

| <b>EOP-004 Attachment 2: Event Reporting Form</b>   |   |
|---|---|
| <p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a> , Facsimile 404-446-9770 or voice: 404-446-9780.</p> |   |
| Task  | Comments  |
| 1.  | <p>Entity filing the report include:<br/>                     Company name:<br/>                     Name of contact person:<br/>                     Email address of contact person:<br/>                     Telephone Number:<br/>                     Submitted by (name):</p>   |
| 2.  | <p>Date and Time of recognized event.<br/>                     Date: (mm/dd/yyyy)<br/>                     Time: (hh:mm)<br/>                     Time/Zone:</p>  |
| 3.  | <p>Did the event originate in your system?      Yes <input type="checkbox"/>    No <input type="checkbox"/>    Unknown <input type="checkbox"/></p>   |
| 4.  | <p style="text-align: center;"><b>Event Identification and Description:</b></p> <p>(Check applicable box)</p> <p><input type="checkbox"/> Damage or destruction of a Facility</p> <p><input type="checkbox"/> Physical Threat to a Facility</p> <p><input type="checkbox"/> Physical Threat to a control center</p> <p><input type="checkbox"/> BES Emergency:</p> <p style="padding-left: 20px;"><input type="checkbox"/> public appeal for load reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> system-wide voltage reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> manual firm load shedding</p> <p style="padding-left: 20px;"><input type="checkbox"/> automatic firm load shedding</p> <p><input type="checkbox"/> Voltage deviation on a Facility</p> <p><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)</p> <p><input type="checkbox"/> Loss of firm load</p> <p><input type="checkbox"/> System separation</p> <p><input type="checkbox"/> Generation loss</p> <p><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)</p> <p><input type="checkbox"/> Transmission loss</p> <p><input type="checkbox"/> unplanned control center evacuation</p> <p><input type="checkbox"/> Complete loss of voice communication capability</p> <p><input type="checkbox"/> Complete loss of monitoring capability</p> <p>Written description (optional):</p> |

## Guideline and Technical Basis

### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

## EOP-004-2(X) — Event Reporting

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reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### Data Gathering

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2(X) specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2(X) may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### Law Enforcement Reporting

The reliability objective of EOP-004-2(X) is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### Stakeholders in the Reporting Process

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF



coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

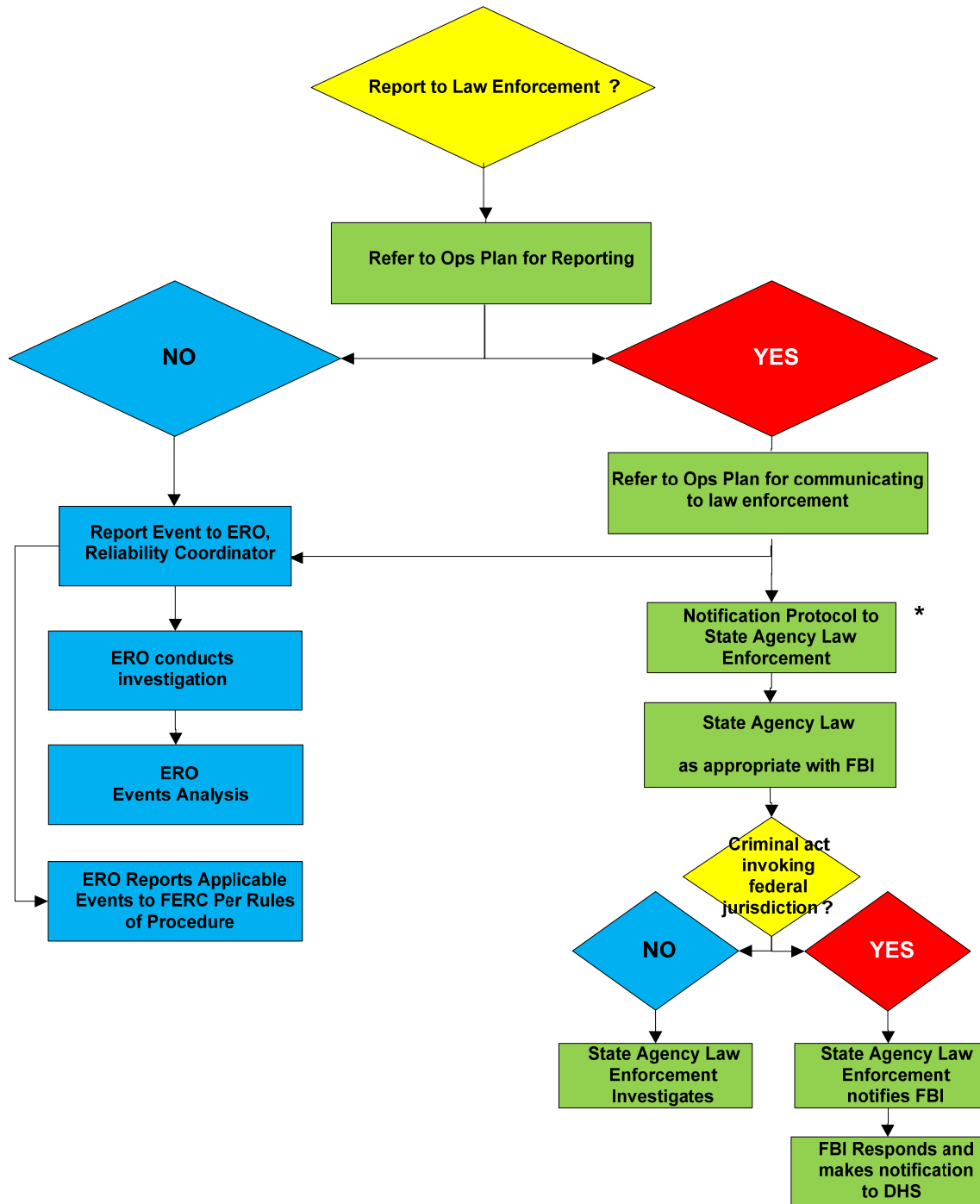
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

## Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

### Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

### Summary of Concepts and Assumptions:

#### *The Standard:*

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

#### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### **Discussion of Event Reporting**

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### ***What about sabotage?***

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2(X) Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

Version History

| Version     | Date             | Action   | Change Tracking   |
|-------------|------------------|--|---|
| 2           |                  | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)   |
| 2           | November 7, 2012 | Adopted by the NERC Board of Trustees  |   |
| 2           | June 20, 2013    | FERC approved  |   |
| <u>2(X)</u> | <u>TBD</u>       | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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### A. Introduction

1. **Title:** System Operating Limits Methodology for the Planning Horizon
2. **Number:** FAC-010-2.1(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Planning Authority
5. **Effective Date:** April 19, 2010

### B. Requirements

- R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the planning horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
    - R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.



## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
  - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
  - R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
  - R2.6.** In determining the system’s response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
    - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
  - R3.2.** Selection of applicable Contingencies.
  - R3.3.** Level of detail of system models used to determine SOLs.
  - R3.4.** Allowed uses of Remedial Action Schemes.
  - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
  - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
  - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.
  - R4.3.** Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### C. Measures

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

##### 1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

##### 1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

###### 1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)

###### 1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

###### 1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

#### 2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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- 2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
  - 2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
  - 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
  - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
  - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
  - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6  |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

**E. Regional Differences**

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
- 1.3.1** Cascading does not occur.
- 1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

### Version History

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |



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|--------|-------------------|--|--|
| 2.1    | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |  |
| 2.1    | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.  |  |
| 2.1(X) | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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### A. Introduction

1. **Title:** System Operating Limits Methodology for the Planning Horizon
2. **Number:** FAC-010-2.1(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Planning Authority
5. **Effective Date:** April 19, 2010

### B. Requirements

- R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the planning horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
    - R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
- R2.6.** In determining the system’s response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
- R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
- R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
- R3.2.** Selection of applicable Contingencies.
- R3.3.** Level of detail of system models used to determine SOLs.
- R3.4.** Allowed uses of ~~Special Protection Systems or Remedial Action~~ [PlansSchemes](#).
- R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
- R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T<sub>v</sub>.
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
- R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
- R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.
- R4.3.** Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### C. Measures

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

##### 1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

##### 1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

###### 1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

(Retirement approved by FERC effective January 21, 2014.)

###### 1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

###### 1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

#### 2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

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- 2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
  - 2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
  - 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
  - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
  - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
  - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

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**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6  |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |



## **E. Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a [Special Protection System Remedial Action Scheme](#) to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |

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|---------------|-------------------|--|---|
| 2.1           | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |   |
| 2.1           | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.  |   |
| <u>2.1(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

- 1. Title:** System Operating Limits Methodology for the Operations Horizon
- 2. Number:** FAC-011-2(X)
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
  - 4.1.** Reliability Coordinator
- 5. Effective Date:** April 29, 2009

**B. Requirements**

- R1.** The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1.** Be applicable for developing SOLs used in the operations horizon.
  - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
  - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Reliability Coordinator’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1.** In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2.** Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1.** Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3.** In determining the system’s response to a single Contingency, the following shall be acceptable:

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
      - R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
      - R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
    - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
  - R3.** The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
    - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
    - R3.2.** Selection of applicable Contingencies
    - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
      - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
    - R3.4.** Level of detail of system models used to determine SOLs.
    - R3.5.** Allowed uses of Remedial Action Schemes.
    - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
    - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
  - R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
    - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
    - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.
    - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.
  - R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

## C. Measures

- M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### 1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### 1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

**1.4.1** SOL Methodology.

- 1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)
  - 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
  - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
- 2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology  
(Retirement approved by FERC effective January 21, 2014.)
  - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
  - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
  - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |



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| Requirement   | Lower   | Moderate  | High  | Severe   |
|---|---|---|---|--|
|   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>   |
| <p>R5<br/>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

## **Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | November 1, 2006  | Adopted by Board of Trustees  | New  |
| 2       |                   | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised  |
| 2       | June 24, 2008     | Adopted by Board of Trustees: FERC Order 705  | Revised  |
| 2       | January 22, 2010  | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update   |
| 2       | February 7, 2013  | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |  |
| 2       | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |  |
| 2       | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.   |  |
| 2(X)    | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-2(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** April 29, 2009

**B. Requirements**

- R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the operations horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
  - R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
  - R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
  - R3.2.** Selection of applicable Contingencies
  - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
    - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
  - R3.4.** Level of detail of system models used to determine SOLs.
  - R3.5.** Allowed uses of ~~Special Protection Systems~~ or Remedial Action ~~Plans~~Schemes.
  - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
  - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
  - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.
  - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

## C. Measures

- M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### 1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### 1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

##### 1.4.1 SOL Methodology.

- 1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)
  - 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
  - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
2. **Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology  
(Retirement approved by FERC effective January 21, 2014.)
  - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
  - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
  - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |



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| Requirement   | Lower   | Moderate  | High  | Severe   |
|---|---|---|---|--|
|   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>   |
| <p>R5<br/>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

## Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a [Special Protection System Remedial Action Scheme](#) to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version          | Date              | Action  | Change Tracking   |
|------------------|-------------------|---|---|
| 1                | November 1, 2006  | Adopted by Board of Trustees  | New   |
| 2                |                   | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised   |
| 2                | June 24, 2008     | Adopted by Board of Trustees: FERC Order 705  | Revised   |
| 2                | January 22, 2010  | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update  |
| 2                | February 7, 2013  | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |   |
| 2                | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |   |
| 2                | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.   |   |
| <del>2</del> (X) | <del>TBD</del>    | <del>Adopted by the NERC Board of Trustees</del>  | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |

## A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-3.1a(X)
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Transmission Service Providers.
  - 4.5. Generator Operators.
  - 4.6. Load-Serving Entities.
  - 4.7. Purchasing-Selling Entities.
5. **Effective Date:**

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

## B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
  - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.
  - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.4. System real and reactive reserves (actual versus required).
  - R1.5. Capacity and energy adequacy conditions.
  - R1.6. Current ACE for all its Balancing Authorities.

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

- R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

**C. Measures**

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance

outages with Transmission Operators, Balancing Authorities and Generator Operators.  
(Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

## **D. Compliance**

### **1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

**1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

None.



**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

**2. Violation Severity Levels:**

| Requirement | Lower   | Moderate  | High  | Severe  |
|-------------|---|---|---|---|
| R1          | The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.   | The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. | The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. | The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. |
| R1.1        | The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.  | N/A   | N/A   | N/A   |
| R1.2        | The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A   | N/A   | N/A   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower  | Moderate | High | Severe |
|-------------|--|----------|------|--------|
| R1.3        | The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A      | N/A  | N/A    |
| R1.4        | The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).  | N/A      | N/A  | N/A    |
| R1.5        | The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.   | N/A      | N/A  | N/A    |
| R1.6        | The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.   | N/A      | N/A  | N/A    |
| R1.7        | The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.   | N/A      | N/A  | N/A    |
| R1.8        | The Reliability Coordinator failed to monitor planned generation dispatches.   | N/A      | N/A  | N/A    |
| R1.9        | The Reliability Coordinator failed to monitor planned transmission or generation outages.  | N/A      | N/A  | N/A    |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower   | Moderate   | High  | Severe  |
|-------------|---|--|---|---|
| R1.10       | The Reliability Coordinator failed to monitor contingency events. | N/A  | N/A   | N/A   |
| R2          | N/A   | The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. | The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.  | The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. |
| R3          | N/A   | N/A  | The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans. | The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.  |
| R4          | N/A   | N/A  | N/A   | The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

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| Requirement | Lower | Moderate | High  | Severe  |
|-------------|-------|----------|---|---|
| R5          | N/A   | N/A      | The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance. | The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition. |

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High  | Severe   |
|-------------|-------|--|---|--|
| R6          | N/A   | <p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real-time reliability analysis time frame or the next-day reliability analysis</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> |
| R7          | N/A   | N/A  | N/A   | <p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
| R8          | N/A   | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS. | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority. | The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.  |
| R9          | N/A   | N/A  | N/A  | The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Remedial Action Scheme that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected. |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
| R10         | N/A   | N/A  | N/A  | The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.   |
| R11         | N/A   | N/A  | N/A  | The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.  |
| R12         | N/A   | The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated. | N/A  | The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities. |

**E. Regional Differences**

None identified.

**Version History**

| Version | Date               | Action  | Change Tracking |
|---------|--------------------|---|-----------------|
| 0       | April 1, 2005      | Effective Date  | New             |
| 0       | August 8, 2005     | Removed “Proposed” from Effective Date  | Errata          |
| 1       |                    | Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17<br>Retired M2 and M3; modified M9 and M12; retired M13<br>Made conforming changes to data retention<br>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)<br>Retired VSLs associated with R2, R3, R5, R16 and R17;<br>Modified VSLs associated with R9 and R13, and R14 | Revised         |
| 2       | November 1, 2006   | Approved by the Board of Trustees   |                 |
| 2       | January 1, 2007    | Effective Date  |                 |
| 2a      | November 5, 2009   | Approved by the Board of Trustees   |                 |
| 3       | October 17, 2008   | Approved by the Board of Trustees   |                 |
| 3       | March 17, 2011     | Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)   |                 |
| 3a      | April 21, 2011     | Added FERC approved Interpretation  |                 |
| 3.1a    | March 8, 2012      | Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)  | Errata          |
| 3.1a    | September 13, 2012 | FERC approved   | Errata          |



**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

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|---------|-------------------|---|--|
| 3.1a    | February 28, 2014 | Updated VSLs based on June 24, 2013 approval. |  |
| 3.1a(X) | TBD               | Adopted by the NERC Board of Trustees         | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Appendix 1

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3</b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0(X) “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p style="text-align: center;"><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12<sup>1</sup></b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation  |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>   |

<sup>1</sup> In the current version of the Standard (IRO-005-3a)(X), this requirement is R9.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-3.1a(X)
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Transmission Service Providers.
  - 4.5. Generator Operators.
  - 4.6. Load-Serving Entities.
  - 4.7. Purchasing-Selling Entities.

5. **Effective Date:**

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

## B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
  - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and ~~Special Protection System~~ Remedial Action Schemes) and system loading.
  - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.4. System real and reactive reserves (actual versus required).
  - R1.5. Capacity and energy adequacy conditions.
  - R1.6. Current ACE for all its Balancing Authorities.

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a ~~Special Protection System~~Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that ~~Special Protection System~~Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the ~~Special Protection System~~Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
- R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

### **C. Measures**

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it

coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a ~~Special Protection System~~Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that ~~Special Protection System~~Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

#### 1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

#### 1.3. Data Retention

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.



**1.4. Additional Compliance Information**

None.

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

**2. Violation Severity Levels:**

| Requirement | Lower   | Moderate  | High  | Severe  |
|-------------|---|---|---|---|
| R1          | The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005- <del>3.1a(X)</del> R1.1 through R1.10.   | The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005- <del>3.1a(X)</del> R1.1 through R1.10. | The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005- <del>3.1a(X)</del> R1.1 through R1.10. | The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005- <del>3.1a(X)</del> R1.1 through R1.10. |
| R1.1        | The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and <del>Special Protection System</del> <del>Remedial Action Schemes</del> ) and system loading. | N/A   | N/A   | N/A   |
| R1.2        | The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.   | N/A   | N/A   | N/A   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower  | Moderate | High | Severe |
|-------------|--|----------|------|--------|
| R1.3        | The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A      | N/A  | N/A    |
| R1.4        | The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).  | N/A      | N/A  | N/A    |
| R1.5        | The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.   | N/A      | N/A  | N/A    |
| R1.6        | The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.   | N/A      | N/A  | N/A    |
| R1.7        | The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.   | N/A      | N/A  | N/A    |
| R1.8        | The Reliability Coordinator failed to monitor planned generation dispatches.   | N/A      | N/A  | N/A    |
| R1.9        | The Reliability Coordinator failed to monitor planned transmission or generation outages.  | N/A      | N/A  | N/A    |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower   | Moderate   | High  | Severe  |
|-------------|---|--|---|---|
| R1.10       | The Reliability Coordinator failed to monitor contingency events. | N/A  | N/A   | N/A   |
| R2          | N/A   | The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. | The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.  | The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. |
| R3          | N/A   | N/A  | The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans. | The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.  |
| R4          | N/A   | N/A  | N/A   | The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate | High  | Severe  |
|-------------|-------|----------|---|---|
| R5          | N/A   | N/A      | The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance. | The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition. |

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High  | Severe   |
|-------------|-------|--|---|--|
| R6          | N/A   | <p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real-time reliability analysis time frame or the next-day reliability analysis</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> |
| R7          | N/A   | N/A  | N/A   | <p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>   |

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
| R8          | N/A   | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS. | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority. | The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.  |
| R9          | N/A   | N/A  | N/A  | The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a <del>Special Protection System</del> Remedial Action Scheme that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the <del>Special Protection System</del> Remedial Action Scheme including any degradation or potential failure to operate as expected. |

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
| R10         | N/A   | N/A  | N/A  | The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.   |
| R11         | N/A   | N/A  | N/A  | The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.  |
| R12         | N/A   | The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated. | N/A  | The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities. |



**E. Regional Differences**

None identified.

**Version History**

| Version | Date               | Action  | Change Tracking |
|---------|--------------------|---|-----------------|
| 0       | April 1, 2005      | Effective Date  | New             |
| 0       | August 8, 2005     | Removed “Proposed” from Effective Date  | Errata          |
| 1       |                    | Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17<br>Retired M2 and M3; modified M9 and M12; retired M13<br>Made conforming changes to data retention<br>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)<br>Retired VSLs associated with R2, R3, R5, R16 and R17;<br>Modified VSLs associated with R9 and R13, and R14 | Revised         |
| 2       | November 1, 2006   | Approved by the Board of Trustees   |                 |
| 2       | January 1, 2007    | Effective Date  |                 |
| 2a      | November 5, 2009   | Approved by the Board of Trustees   |                 |
| 3       | October 17, 2008   | Approved by the Board of Trustees   |                 |
| 3       | March 17, 2011     | Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)   |                 |
| 3a      | April 21, 2011     | Added FERC approved Interpretation  |                 |
| 3.1a    | March 8, 2012      | Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)  | Errata          |
| 3.1a    | September 13, 2012 | FERC approved   | Errata          |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

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|                |                   |   |   |
|----------------|-------------------|---|---|
| 3.1a           | February 28, 2014 | Updated VSLs based on June 24, 2013 approval. |   |
| <u>3.1a(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Appendix 1

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3</b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0(X) “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or degraded <u>special protection system Remedial Action Schemes</u>. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12<sup>1</sup></b></p> <p><b>R12.</b> Whenever a <u>Special Protection System Remedial Action Scheme</u> that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that <u>Special Protection System Remedial Action Scheme</u> on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the <u>Special Protection System Remedial Action Scheme</u> including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use <del>an SPS RAS</del> shall have a documented Regional Reliability Organization <del>RASSPS</del> review procedure to ensure that <del>SPSs RASs</del> comply with Regional criteria and NERC Reliability Standards. The Regional <del>SPS RAS</del> review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the <del>SPS RAS</del> shall be designed so that a single <del>SPS RAS</del> component failure, when the <del>SPS RAS</del> was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| <p><b>Background Information for Interpretation</b></p> <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>   |

<sup>1</sup> In the current version of the Standard (IRO-005-3a)(X), this requirement is R9.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPSRAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a SPS RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPSRAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a SPS RAS to operate as designed. If the loss of a communication channel will result in the failure of a SPS RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPSRAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

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### A. Introduction

1. **Title:** Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
2. **Number:** IRO-014-1(X)
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** November 1, 2006

### B. Requirements

- R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.
  - R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:
    - R1.1.1. Communications and notifications, including the conditions<sup>1</sup> under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.
    - R1.1.2. Energy and capacity shortages.
    - R1.1.3. Planned or unplanned outage information.
    - R1.1.4. Voltage control, including the coordination of reactive resources for voltage control.
    - R1.1.5. Coordination of information exchange to support reliability assessments.
    - R1.1.6. Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.
- R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:
  - R2.1. Agreed to by all the Reliability Coordinators required to take the indicated action(s).
  - R2.2. Distributed to all Reliability Coordinators that are required to take the indicated action(s).
- R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:
  - R3.1. A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

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<sup>1</sup> Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of Remedial Action Schemes, etc.

## Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

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**R3.2.** The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

**R4.** Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:

**R4.1.** Include version control number or date.

**R4.2.** Include a distribution list.

**R4.3.** Be reviewed, at least once every three years, and updated if needed.

### C. Measures

**M1.** The Reliability Coordinator's System Operators shall have available for Real-time use, the latest approved version of Operating Procedures, Processes, or Plans that require notifications, information exchange or the coordination of actions between Reliability Coordinators.

**M1.1** These Operating Procedures, Processes, or Plans shall address:

**M1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

**M2.1.1** Energy and capacity shortages.

**M3.1.1** Planned or unplanned outage information.

**M4.1.1** Voltage control, including the coordination of reactive resources for voltage control.

**M5.1.1** Coordination of information exchange to support reliability assessments.

**M6.1.1** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

**M2.** The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were:

**M2.1** Agreed to by all the Reliability Coordinators required to take the indicated action(s).

**M2.2** Distributed to all Reliability Coordinators that are required to take the indicated action(s).

**M3.** The Reliability Coordinator's Operating Procedures, Processes, or Plans developed (for its System Operators' internal use) to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan received from another Reliability Coordinator shall:

**M3.1** Be available to the Reliability Coordinator's System Operators for Real-time use,

**M3.2** Include a reference to the associated source document, and

**M3.3** Support the agreed-upon actions from the source document.

**M4.** The Reliability Coordinator's Operating Procedures, Processes, or Plans that addresses Reliability Coordinator-to-Reliability Coordinator coordination shall each include a version control number or date and a distribution list. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were reviewed within the last three years.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

**1.2. Compliance Monitoring Period and Reset Time Frame**

The Performance-Reset Period shall be one calendar year.

**1.3. Data Retention**

The Reliability Coordinator shall keep documentation for the prior calendar year and the current calendar year. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

**1.4. Additional Compliance Information**

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators to identify Operating Procedures, Processes or Plans that were distributed to the Reliability Coordinator being audited to verify that these documents are available for Real-time use by the receiving Reliability Coordinator's System Operators.

The Reliability Coordinator shall have the following documents available for inspection during an on-site audit or within five business days of a request as part of an investigation upon a complaint:

**1.4.1** The latest version of its Operating Procedures, Processes, or Plans that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.

**1.4.2** Evidence of distribution of Operating Procedures, Processes, or Plans.

**2. Levels of Non-Compliance**

**2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions is present:

**2.1.1** The latest versions of Operating Procedures, Processes, or Plans (identified through self-certification) that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability do not include a version control number or date, and a distribution list.

**2.1.2** The latest versions of Reliability Coordinator internal documents developed to support action(s) required as a result of other Reliability Coordinators do not include both a reference to the source Operating Procedure, Process, or Plan and the agreed-upon actions from the source Operating Procedure, Process, or Plan.

**2.2. Level 2:** There shall be a level two non-compliance if any of the following conditions is present:

**2.2.1** Documents required by this standard were not distributed to all entities on the distribution list.

**2.2.2** Documents required by this standard were not available for System Operators' Real-time use.

**2.2.3** Documents required by this standard do not address all required topics.

**2.3. Level 3:** Documents required by this standard do not address any of the six required topics in Reliability Standard IRO-014-1(X) R1.

**2.4. Level 4:** Not Applicable.

**Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators**

**E. Regional Differences**

None Identified.

**Version History**

| <b>Version</b> | <b>Date</b> | <b>Action</b>  | <b>Change Tracking</b>   |
|----------------|-------------|--|--|
| Version 1      | 08/10/05    | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash (–).”</li> <li>2. Hyphenated “30-day” when used as adjective.</li> <li>3. Changed standard header to be consistent with standard “Title.”</li> <li>4. Initial capped heading “Definitions of Terms Used in Standard.”</li> <li>5. Added “periods” to items where appropriate.</li> <li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> <li>7. Lower cased all words that are not “defined” terms — drafting team, self-certification.</li> <li>8. Changed apostrophes to “smart” symbols.</li> <li>9. Added comma in all word strings “Procedures, Processes, or Plans,” etc.</li> <li>10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective.</li> <li>11. Removed comma in item 2.1.2.</li> <li>12. Removed extra spaces between words where appropriate.</li> </ol> | 01/20/06   |
| 1(X)           | TBD         | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

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### A. Introduction

1. **Title:** Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
2. **Number:** IRO-014-1(X)
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** November 1, 2006

### B. Requirements

- R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.
  - R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:
    - R1.1.1. Communications and notifications, including the conditions<sup>1</sup> under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.
    - R1.1.2. Energy and capacity shortages.
    - R1.1.3. Planned or unplanned outage information.
    - R1.1.4. Voltage control, including the coordination of reactive resources for voltage control.
    - R1.1.5. Coordination of information exchange to support reliability assessments.
    - R1.1.6. Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.
- R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:
  - R2.1. Agreed to by all the Reliability Coordinators required to take the indicated action(s).
  - R2.2. Distributed to all Reliability Coordinators that are required to take the indicated action(s).
- R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:
  - R3.1. A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

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<sup>1</sup> Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of [special-protection system Remedial Action Schemes](#), etc.

**R3.2.** The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

**R4.** Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:

**R4.1.** Include version control number or date.

**R4.2.** Include a distribution list.

**R4.3.** Be reviewed, at least once every three years, and updated if needed.

## **C. Measures**

**M1.** The Reliability Coordinator's System Operators shall have available for Real-time use, the latest approved version of Operating Procedures, Processes, or Plans that require notifications, information exchange or the coordination of actions between Reliability Coordinators.

**M1.1** These Operating Procedures, Processes, or Plans shall address:

**M1.1.1** Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

**M2.1.1** Energy and capacity shortages.

**M3.1.1** Planned or unplanned outage information.

**M4.1.1** Voltage control, including the coordination of reactive resources for voltage control.

**M5.1.1** Coordination of information exchange to support reliability assessments.

**M6.1.1** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

**M2.** The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were:

**M2.1** Agreed to by all the Reliability Coordinators required to take the indicated action(s).

**M2.2** Distributed to all Reliability Coordinators that are required to take the indicated action(s).

**M3.** The Reliability Coordinator's Operating Procedures, Processes, or Plans developed (for its System Operators' internal use) to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan received from another Reliability Coordinator shall:

**M3.1** Be available to the Reliability Coordinator's System Operators for Real-time use,

**M3.2** Include a reference to the associated source document, and

**M3.3** Support the agreed-upon actions from the source document.

**M4.** The Reliability Coordinator's Operating Procedures, Processes, or Plans that addresses Reliability Coordinator-to-Reliability Coordinator coordination shall each include a version control number or date and a distribution list. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were reviewed within the last three years.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

**1.2. Compliance Monitoring Period and Reset Time Frame**

The Performance-Reset Period shall be one calendar year.

**1.3. Data Retention**

The Reliability Coordinator shall keep documentation for the prior calendar year and the current calendar year. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

**1.4. Additional Compliance Information**

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators to identify Operating Procedures, Processes or Plans that were distributed to the Reliability Coordinator being audited to verify that these documents are available for Real-time use by the receiving Reliability Coordinator's System Operators.

The Reliability Coordinator shall have the following documents available for inspection during an on-site audit or within five business days of a request as part of an investigation upon a complaint:

**1.4.1** The latest version of its Operating Procedures, Processes, or Plans that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.

**1.4.2** Evidence of distribution of Operating Procedures, Processes, or Plans.

**2. Levels of Non-Compliance**

**2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions is present:

**2.1.1** The latest versions of Operating Procedures, Processes, or Plans (identified through self-certification) that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability do not include a version control number or date, and a distribution list.

**2.1.2** The latest versions of Reliability Coordinator internal documents developed to support action(s) required as a result of other Reliability Coordinators do not include both a reference to the source Operating Procedure, Process, or Plan and the agreed-upon actions from the source Operating Procedure, Process, or Plan.

**2.2. Level 2:** There shall be a level two non-compliance if any of the following conditions is present:

**2.2.1** Documents required by this standard were not distributed to all entities on the distribution list.

**2.2.2** Documents required by this standard were not available for System Operators' Real-time use.

**2.2.3** Documents required by this standard do not address all required topics.

**2.3. Level 3:** Documents required by this standard do not address any of the six required topics in Reliability Standard IRO-014-1(X) R1.

**2.4. Level 4:** Not Applicable.

**Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators**

**E. Regional Differences**

None Identified.

**Version History**

| Version              | Date                | Action   | Change Tracking  |
|----------------------|---------------------|--|--|
| Version 1            | 08/10/05            | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash (–).”</li> <li>2. Hyphenated “30-day” when used as adjective.</li> <li>3. Changed standard header to be consistent with standard “Title.”</li> <li>4. Initial capped heading “Definitions of Terms Used in Standard.”</li> <li>5. Added “periods” to items where appropriate.</li> <li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> <li>7. Lower cased all words that are not “defined” terms — drafting team, self-certification.</li> <li>8. Changed apostrophes to “smart” symbols.</li> <li>9. Added comma in all word strings “Procedures, Processes, or Plans,” etc.</li> <li>10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective.</li> <li>11. Removed comma in item 2.1.2.</li> <li>12. Removed extra spaces between words where appropriate.</li> </ol> | 01/20/06   |
| <a href="#">1(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>  | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

**A. Introduction**

- 1. Title:** Rated System Path Methodology
- 2. Number:** MOD-029-1a(X)
- 3. Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
- 4. Applicability:**
  - 4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
- 5. Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

**B. Requirements**

- R1.** When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R1.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1.** Includes at least:
      - R1.1.1.1.** The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2.** All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3.** Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)
    - R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.
    - R1.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
    - R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).



Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**NL<sub>F</sub>** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the

effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.



**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

**C. Measures**

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
  - M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
  - M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
  - M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
  - M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1(X) and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |

**Standard MOD-029-1a(X) — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

**Standard MOD-029-1a(X) — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |

**Version History**

| Version | Date                         | Action   | Change Tracking  |
|---------|------------------------------|--|--|
| 1       | 8/26/2008                    | Adopted by NERC Board of Trustees                |  |
| 1a      | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)  |
| 1a      | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |  |
| 1a(X)   | TBD                          | Adopted by the NERC Board of Trustees            | Replaced references to<br>Special Protection<br>System and SPS with<br>Remedial Action Scheme<br>and RAS |



## Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> <li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li> <li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li> <li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li> </ul> <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> <li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li> <li><b>R8.2.</b> Daily values, once per day.</li> <li><b>R8.3.</b> Monthly values, once per week.</li> </ul> |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>   |

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01(X) Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL<sub>F</sub> is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS<sub>F</sub> is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF<sub>F</sub> is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP<sub>F</sub> is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR<sub>F</sub> is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS<sub>F</sub> is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS<sub>NF</sub> is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_{NF}$  is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_{NF}$  is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

$OS_{NF}$  is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could  $OS_F$  in MOD-029-1(X) Requirement R5 and  $OS_{NF}$  in MOD-029-1(X) Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## A. Introduction

1. **Title:** Rated System Path Methodology
2. **Number:** MOD-029-1a(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

## B. Requirements

- R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1. Includes at least:
      - R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)
    - R1.1.2. Models all system Elements as in-service for the assumed initial conditions.
    - R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
    - R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

- R1.1.5. Uses Load forecast by Balancing Authority.
  - R1.1.6. Uses Transmission Facility additions and retirements.
  - R1.1.7. Uses Generation Facility additions and retirements.
  - R1.1.8. Uses [Special Protection System \(SPS\) Remedial Action Scheme \(RAS\)](#) models where currently existing or projected for implementation within the studied time horizon.
  - R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
  - R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.
  - R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R2. The Transmission Operator shall use the following process to determine TTC:  
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R2.1. Except where otherwise specified within MOD-029-1(X), adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:
    - R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
    - R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
    - R2.1.3. Uncontrolled separation shall not occur.
  - R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a [Special Protection System \(SPS\) Remedial Action Scheme \(RAS\)](#), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a [RASSPS](#).
  - R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.
  - R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

- R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.
- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**NL<sub>F</sub>** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postback_{SF} + counterflows_{SF}$$

**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.



### C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a [Special Protection System Remedial Action Scheme](#) where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1(X) and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any

recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |

**Standard MOD-029-1a(X)— Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

**Standard MOD-029-1a(X)— Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |

**Version History**

| Version       | Date                         | Action   | Change Tracking   |
|---------------|------------------------------|--|---|
| 1             | 8/26/2008                    | Adopted by NERC Board of Trustees                |   |
| 1a            | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)   |
| 1a            | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |   |
| <del>1a</del> | <del>TBD</del>               | <del>Adopted by the NERC Board of Trustees</del> | <del>Replaced references to<br/>Special Protection<br/>System and SPS with<br/>Remedial Action Scheme<br/>and RAS</del> |

## Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> <li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li> <li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li> <li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li> </ul> <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> <li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li> <li><b>R8.2.</b> Daily values, once per day.</li> <li><b>R8.3.</b> Monthly values, once per week.</li> </ul> |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>   |



The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01(X) Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL<sub>F</sub> is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS<sub>F</sub> is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF<sub>F</sub> is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP<sub>F</sub> is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR<sub>F</sub> is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS<sub>F</sub> is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS<sub>NF</sub> is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_{NF}$  is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_{NF}$  is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

$OS_{NF}$  is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could  $OS_F$  in MOD-029-1(X) Requirement R5 and  $OS_{NF}$  in MOD-029-1(X) Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## A. Introduction

1. **Title:** Flowgate Methodology
2. **Number:** MOD-030-02(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

## B. Requirements

- R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3. The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
      - R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the

applicable time periods, including use of Remedial Action Schemes.

**R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

**R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

**R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

**R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
  - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

- R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ( $ETC_{Fi}$ ) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
  - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC<sub>NFi</sub>) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider’s area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{SFi} + counterflows_{SFi}$$

**Where:**

**AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.

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<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.



**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

**C. Measures**

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

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<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the

value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

#### **1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>   | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>  |



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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>• The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>• The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |

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| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| Version | Date | Action  | Change Tracking  |
|---------|------|---|--|
| 2       |      | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised  |
| 2(X)    | TBD  | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Flowgate Methodology
2. **Number:** MOD-030-02(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

## B. Requirements

- R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3. The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
      - R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the

applicable time periods, including use of [Special Protection System Remedial Action Schemes](#).

- R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.
- R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.
- R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.
  - R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of [Special Protection System Remedial Action Schemes](#).
  - R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.
  - R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.
- R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.
- R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:
  - R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and
    - Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
    - A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
  - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

- R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the



Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments (ETC<sub>Fi</sub>) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
  - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC<sub>NFi</sub>) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider’s area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{SFi} + counterflows_{SFi}$$

**Where:**

**AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.

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<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

**C. Measures**

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

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<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the

value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

#### **1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.



2. Violation Severity Levels

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>   | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>  |

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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>• The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>• The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |

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| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| Version          | Date       | Action  | Change Tracking   |
|------------------|------------|---|---|
| 2                |            | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised   |
| <del>2</del> (X) | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |



**A. Introduction**

- 1. Title:** Nuclear Plant Interface Coordination
- 2. Number:** NUC-001-2.1(X)
- 3. Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
- 4. Applicability:**
  - 4.1.** Nuclear Plant Generator Operator.
  - 4.2.** Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
    - 4.2.1** Transmission Operators.
    - 4.2.2** Transmission Owners.
    - 4.2.3** Transmission Planners.
    - 4.2.4** Transmission Service Providers.
    - 4.2.5** Balancing Authorities.
    - 4.2.6** Reliability Coordinators.
    - 4.2.7** Planning Coordinators.
    - 4.2.8** Distribution Providers.
    - 4.2.9** Load-serving Entities.
    - 4.2.10** Generator Owners.
    - 4.2.11** Generator Operators.
- 5. Effective Date:** April 1, 2010

**B. Requirements**

- R1.** The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements<sup>1</sup> that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]
- R3.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

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1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
  - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
  - R4.2.** Operate the electric system to meet the NPIRs.
  - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
  - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
  - R9.2.** Technical requirements and analysis:
    - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.
    - R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
    - R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
  - R9.3.** Operations and maintenance coordination:

- R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
- R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
- R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
- R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
- R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
- R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
- R9.3.7.** Coordination of the NPIRs with transmission system Remedial Action Schemes and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
  - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
  - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
  - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
  - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
  - R9.4.5.** Provisions for personnel training, as related to NPIRs.

**C. Measures**

- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
  - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
  - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
  - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Enforcement Authority**

Regional Entity.
  - 1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.
  - 1.3. Compliance Monitoring and Enforcement Processes:**
    - Compliance Audits
    - Self-Certifications
    - Spot Checking
    - Compliance Violation Investigations
    - Self-Reporting

Complaints

**1.4. Data Retention**

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

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

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

**1.5. Additional Compliance Information**

None.

**2. Violation Severity Levels**

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

**E. Regional Differences**

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

**Nuclear Plant Licensing Requirements (NPLR)** are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this

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standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

**F. Associated Documents**

**Version History**

| Version | Date              | Action   | Change Tracking  |
|---------|-------------------|--|--|
| 1       | May 2, 2007       | Approved by Board of Trustees  | New  |
| 2       | To be determined  | Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.                             | Revision   |
| 2       | August 5, 2009    | Adopted by Board of Trustees   | Revised  |
| 2       | January 22, 2010  | Approved by FERC on January 21, 2010<br>Added Effective Date   | Update   |
| 2       | February 7, 2013  | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. |  |
| 2.1     | April 11, 2012    | Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)                   | Errata associated with Project 2007-17   |
| 2.1     | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.   |  |
| 2.1     | November 21, 2013 | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)   |  |
| 2.1(X)  | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** Nuclear Plant Interface Coordination
2. **Number:** NUC-001-2.1(X)
3. **Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
4. **Applicability:**
  - 4.1. Nuclear Plant Generator Operator.
  - 4.2. Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
    - 4.2.1 Transmission Operators.
    - 4.2.2 Transmission Owners.
    - 4.2.3 Transmission Planners.
    - 4.2.4 Transmission Service Providers.
    - 4.2.5 Balancing Authorities.
    - 4.2.6 Reliability Coordinators.
    - 4.2.7 Planning Coordinators.
    - 4.2.8 Distribution Providers.
    - 4.2.9 Load-serving Entities.
    - 4.2.10 Generator Owners.
    - 4.2.11 Generator Operators.
5. **Effective Date:** April 1, 2010

**B. Requirements**

- R1. The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements<sup>1</sup> that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]
- R3. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

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1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
  - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
  - R4.2.** Operate the electric system to meet the NPIRs.
  - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
  - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
  - R9.2.** Technical requirements and analysis:
    - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.
    - R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
    - R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
  - R9.3.** Operations and maintenance coordination:



- R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
- R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
- R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
- R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
- R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
- R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
- R9.3.7.** Coordination of the NPIRs with transmission system [Special Protection System Remedial Action Schemes](#) and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
  - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
  - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
  - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
  - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
  - R9.4.5.** Provisions for personnel training, as related to NPIRs.

**C. Measures**

- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
  - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
  - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
  - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Enforcement Authority**

Regional Entity.
  - 1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.
  - 1.3. Compliance Monitoring and Enforcement Processes:**
    - Compliance Audits
    - Self-Certifications
    - Spot Checking
    - Compliance Violation Investigations
    - Self-Reporting

Complaints

**1.4. Data Retention**

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

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

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

**1.5. Additional Compliance Information**

None.

**2. Violation Severity Levels**

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

**E. Regional Differences**

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

**Nuclear Plant Licensing Requirements (NPLR)** are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this

**Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination**

standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

**F. Associated Documents**

**Version History**

| Version       | Date              | Action   | Change Tracking   |
|---------------|-------------------|--|---|
| 1             | May 2, 2007       | Approved by Board of Trustees  | New   |
| 2             | To be determined  | Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.                             | Revision  |
| 2             | August 5, 2009    | Adopted by Board of Trustees   | Revised   |
| 2             | January 22, 2010  | Approved by FERC on January 21, 2010<br>Added Effective Date   | Update  |
| 2             | February 7, 2013  | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. |   |
| 2.1           | April 11, 2012    | Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)                   | Errata associated with Project 2007-17  |
| 2.1           | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.   |   |
| 2.1           | November 21, 2013 | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)   |   |
| <u>2.1(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(X)
3. **Purpose:**  
To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** January 1, 2007

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.
- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

**C. Measures**

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 6 Part 2)

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

**1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will

have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

## **2. Levels of Non-Compliance for Generator Operators:**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

## **3. Levels of Non-Compliance for Transmission Operators:**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

**3.3. Level 3:** Not applicable.

**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 0       | April 1, 2005     | Effective Date  | New  |
| 0       | August 8, 2005    | Removed “Proposed” from Effective Date  | Errata   |
| 0       | August 25, 2005   | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata   |
| 1       | November 1, 2006  | Adopted by Board of Trustees  | Revised  |
| 1.1     | April 11, 2012    | Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”) | Errata associated with Project 2007-17   |
| 1.1     | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.  |  |
| 1.1(X)  | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(X)
3. **Purpose:**  
To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** January 1, 2007

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.
- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6. Each Transmission Operator and Balancing Authority shall monitor the status of each ~~Special Protection System~~ Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

### C. Measures

- M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the ~~Special Protection System~~ Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its ~~Special Protection System~~ Remedial Action Schemes. (Requirement 6 Part 2)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

##### 1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)

- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

## **2. Levels of Non-Compliance for Generator Operators:**

- 2.1. Level 1:** Not applicable.
- 2.2. Level 2:** Not applicable.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

## **3. Levels of Non-Compliance for Transmission Operators:**

- 3.1. Level 1:** Not applicable.
- 3.2. Level 2:** Not applicable.
- 3.3. Level 3:** Not applicable.
- 3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
  - 3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each ~~Special Protection System Remedial Action Scheme~~, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each ~~Special Protection System Remedial Action Scheme~~, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

| Version                | Date                | Action  | Change Tracking  |
|------------------------|---------------------|---|--|
| 0                      | April 1, 2005       | Effective Date  | New  |
| 0                      | August 8, 2005      | Removed “Proposed” from Effective Date  | Errata   |
| 0                      | August 25, 2005     | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata   |
| 1                      | November 1, 2006    | Adopted by Board of Trustees  | Revised  |
| 1.1                    | April 11, 2012      | Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”) | Errata associated with Project 2007-17   |
| 1.1                    | September 9, 2013   | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.  |  |
| <a href="#">1.1(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>   | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

## **A. Introduction**

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-1(X)
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

### **4. Applicability**

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
  - 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
  - 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** On the first day of the second quarter following applicable regulatory approval.

## **B. Requirements**

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the

Transmission Owner or Generator Owner identifies the Misoperation:

- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
  - R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
  - R2.3.2.** When FERAS is not available, then
    - 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
    - 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
  - R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or
  - R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
- R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to

WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
- R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

### **C. Measures**

**Each measure below applies directly to the requirement by number.**

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
  - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
  - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
  - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
  - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
    - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
  - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
    - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.
  - M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
    - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

**R1**

|              |                 |             |               |
|--------------|-----------------|-------------|---------------|
| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|



**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

|   |   |  |  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |
|---|---|--|--|

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.2.2 and R2.4**

| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|
|              |                 |             |               |

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

|  |   |   |  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |
|--|---|---|--|

**R3.1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| <b>Version</b> | <b>Date</b>    | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|----------------|--|------------------------|
| 1              | April 16, 2008 | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1 |                        |

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

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|      |                |   |  |
|------|----------------|---|--|
| 1    | April 21, 2011 | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |  |
| 1(X) | TBD            | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## **A. Introduction**

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-1(X)
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

### **4. Applicability**

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** On the first day of the second quarter following applicable regulatory approval.

## **B. Requirements**

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the

Transmission Owner or Generator Owner identifies the Misoperation:

- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
  - R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
  - R2.3.2.** When FERAS is not available, then
    - 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
    - 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
  - R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or
  - R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
- R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to

WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
- R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

### **C. Measures**

**Each measure below applies directly to the requirement by number.**

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
  - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
  - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
  - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
  - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
    - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
  - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
    - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.
  - M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
    - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

**R1**

|              |                 |             |               |
|--------------|-----------------|-------------|---------------|
| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

|   |   |  |  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |
|---|---|--|--|

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.2.2 and R2.4**

| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|
|              |                 |             |               |



**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

|  |   |   |  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |
|--|---|---|--|

**R3.1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| <b>Version</b> | <b>Date</b>    | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|----------------|--|------------------------|
| 1              | April 16, 2008 | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1 |                        |

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

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|             |                |   |   |
|-------------|----------------|---|---|
| 1           | April 21, 2011 | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |   |
| <u>1(X)</u> | <u>TBD</u>     | <u>Adopted by the NERC Board of Trustees</u>                                  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
5. **Effective Date:** See Implementation Plan

**B. Requirements**

- R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**Component Type** - Any one of the five specific elements of the Protection System definition.

**Component** – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

**Unresolved Maintenance Issue** - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

## **C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## **D. Compliance**

- 1. Compliance Monitoring Process**
- 1.1. Compliance Enforcement Authority**  
Regional Entity
- 1.2. Compliance Monitoring and Enforcement Processes:**  
Compliance Audit  
Self-Certification  
Spot Checking  
Compliance Investigation  
Self-Reporting  
Complaint

### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|--------------------|---|---|--|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,</li> </ul> </li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,</li> <li style="text-align: center;">OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>   |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or   | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10   | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15   | The responsible entity failed to undertake efforts to correct greater   |



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| <b>Requirement Number</b> | <b>Lower VSL</b>                                | <b>Moderate VSL</b>                       | <b>High VSL</b>                           | <b>Severe VSL</b>                                 |
|---------------------------|---|---|---|---|
|                           | fewer identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(X) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|      |                   |  |  |
|------|-------------------|--|--|
| 1.1b | May 9, 2012       | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).   |  |
| 2    | November 7, 2012  | Adopted by Board of Trustees   | Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2    | October 17, 2013  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.  |  |
| 2    | December 19, 2013 | FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. |  |
| 2(X) | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS           |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 calendar years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |





| <b>Table 1-4(b)</b><br><b>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |   |   |
|---|---|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).                       |   |   |
| Component Attributes  | Maximum Maintenance Interval                  | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|   | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|   | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|   | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |



| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <b>Table 1-4(d)</b><br><b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).              |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

Table 1-4(e)

**Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems**

| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
|--|--|-----------------------------------|
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RASs except as noted.</b> |                                   |   |
|--|-----------------------------------|---|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.   | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified | None.   |



| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.   | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 calendar years             | <p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 calendar years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 calendar years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

PRC-005 — Attachment A

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**Segment** – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

**Countable Event** – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a ~~Special Protection System (SPS)~~ Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
5. **Effective Date:** See Implementation Plan

## B. Requirements

- R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**Component Type** - Any one of the five specific elements of the Protection System definition.

**Component** – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

**Unresolved Maintenance Issue** - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

## **C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## **D. Compliance**

- 1. Compliance Monitoring Process**
- 1.1. Compliance Enforcement Authority**  
Regional Entity
- 1.2. Compliance Monitoring and Enforcement Processes:**  
Compliance Audit  
Self-Certification  
Spot Checking  
Compliance Investigation  
Self-Reporting  
Complaint



### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|--------------------|---|---|--|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,</li> </ul> </li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,</li> <li style="text-align: center;">OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>   |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or   | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10   | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15   | The responsible entity failed to undertake efforts to correct greater   |

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| <b>Requirement Number</b> | <b>Lower VSL</b>                                | <b>Moderate VSL</b>                       | <b>High VSL</b>                           | <b>Severe VSL</b>                                 |
|---------------------------|---|---|---|---|
|                           | fewer identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(X) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|             |                   |  |  |
|-------------|-------------------|--|--|
| 1.1b        | May 9, 2012       | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).   |  |
| 2           | November 7, 2012  | Adopted by Board of Trustees   | Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2           | October 17, 2013  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.  |  |
| 2           | December 19, 2013 | FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. |  |
| <u>2(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>    |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 calendar years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |



| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |



Table 1-4(b)

**Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for SPSRAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes   | Maximum Maintenance Interval                  | Maintenance Activities  |
|--|---|---|
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|  | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |



Table 1-4(c)

**Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for SPSRAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <b>Table 1-4(d)</b><br><b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>   |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for <del>SPSRAS</del> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |



Table 1-4(e)

Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for **SPSRAS**, non-distributed UFLS, and non-distributed UVLS systems

| Component Attributes  | Maximum Maintenance Interval                       | Maintenance Activities            |
|---|--|-----------------------------------|
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <b>SPSRAS</b> , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <u>SPSRAS</u>s except as noted.</b> |                                   |   |
|--|-----------------------------------|---|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with <u>SPSRAS</u> .  | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the <u>SPSRAS</u> .  |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or <u>SPSRAS</u> whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.   | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 calendar years             | <p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 calendar years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 calendar years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

PRC-005 — Attachment A

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**Segment** – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

**Countable Event** – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.



**A. Introduction**

- 1. Title:** Protection System and Automatic Reclosing Maintenance
- 2. Number:** PRC-005-3(X)
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
  - 4.1. Functional Entities:**
    - 4.1.1** Transmission Owner
    - 4.1.2** Generator Owner
    - 4.1.3** Distribution Provider
  - 4.2. Facilities:**
    - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4** Protection Systems installed as a Remedial Action Schemes (RAS) for BES reliability.
    - 4.2.5** Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6** Automatic Reclosing<sup>1</sup>, including:
      - 4.2.6.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

**4.2.6.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.6.3** Automatic Reclosing applied as an integral part of a RAS specified in Section 4.2.4.

**5. Effective Date:** See Implementation Plan

**6. Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

**B. Requirements**

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate

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monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Enforcement Authority**

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

##### **1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

##### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

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**2. Violation Severity Levels**

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|--------------------|---|---|---|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>  | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.    |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |



**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|      |                  |   |  |
|------|------------------|---|--|
| 1.1b | May 9, 2012      | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).  |  |
| 2    | November 7, 2012 | Adopted by Board of Trustees  | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2    | October 17, 2013 | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing |  |
| 3    | November 7, 2013 | Adopted by the NERC Board of Trustees   | Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.              |
| 3(X) | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS                               |

| <b>Table 1-1<br/>                     Component Type - Protective Relay<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>   |   |   |
|--|---|---|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval<sup>2</sup></b> | <b>Maintenance Activities</b>   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                                | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                               | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 Calendar Years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 Calendar Months            | Verify that the communications system is functional.   |
|   | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| <b>Table 1-3</b><br><b>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)          |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |



| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3) |                              |   |
|--|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |                              |   |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(b)**  
**Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                  | Maintenance Activities  |
|----------------------|---|---|
|                      | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| Table 1-4(d)<br>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|  | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|  | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.</b> |                                   |   |
|---|-----------------------------------|---|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.<br>(See Table 4-2(b) for RAS which include Automatic Reclosing.)   | 12 Calendar Years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.   | 12 Calendar Years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).   | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.  | No periodic maintenance specified | None.  |



| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | <p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 Calendar Years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 Calendar Years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing Relay   |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |

| <b>Table 4-2(a)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a RAS</b> |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a RAS.   | 12 Calendar Years                   | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of a RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)                                | No periodic maintenance specified   | None.  |

| <b>Table 4-2(b)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of a RAS</b> |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of a RAS (regardless of any monitoring of the control circuitry).                        | 6 Calendar Years                    | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.                             |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of a RAS.   | 12 Calendar Years                   | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS. |
| Control circuitry associated with Automatic Reclosing that is an integral part of a RAS whose integrity is monitored and alarmed. (See Table 2)  | No periodic maintenance specified   | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-3(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a [Special Protection System \(SPS\) Remedial Action Schemes \(RAS\)](#) for BES reliability.
    - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6 Automatic Reclosing<sup>1</sup>, including:
      - 4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

**4.2.6.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.6.3** Automatic Reclosing applied as an integral part of an [SPS](#) [RAS](#) specified in Section 4.2.4.

**5. Effective Date:** See Implementation Plan

**6. Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.



## B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
  - 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

## C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate

monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

#### **1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|--------------------|---|---|---|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>  | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.    |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

|             |                  |   |  |
|-------------|------------------|---|--|
| 1.1b        | May 9, 2012      | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).  |  |
| 2           | November 7, 2012 | Adopted by Board of Trustees  | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2           | October 17, 2013 | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing |  |
| 3           | November 7, 2013 | Adopted by the NERC Board of Trustees   | Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.              |
| <u>3(X)</u> | <u>TBD</u>       | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>                        |



| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 Calendar Years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 Calendar Months            | Verify that the communications system is functional.   |
|   | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| <b>Table 1-3<br/>                     Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for [SPSRAS](#), non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for [SPSRAS](#), non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)                    |                              |   |
|---|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for <a href="#">SPSRAS</a> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |   |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|   | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(b)**  
**Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for [SPSRAS](#), non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                  | Maintenance Activities  |
|----------------------|---|---|
|                      | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |



Table 1-4(c)  
 Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries  
 Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

**Table 1-4(d)**  
**Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for <a href="#">SPSRAS</a> , non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <a href="#">SPSRAS</a> , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| Table 1-5<br>Component Type - Control Circuitry Associated With Protective Functions<br>Excluding distributed UFLS and distributed UVLS (see Table 3)                                       |                                   |   |
|---|-----------------------------------|---|
| Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <b>SPSRAS</b> except as noted.  |                                   |   |
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry). | 6 Calendar Years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with <b>SPSRAS</b> .<br>(See Table 4-2(b) for <b>SPSRAS</b> which include Automatic Reclosing.)  | 12 Calendar Years                 | Verify all paths of the control circuits essential for proper operation of the <b>SPSRAS</b> .  |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.   | 12 Calendar Years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or <b>SPSRAS</b> whose integrity is monitored and alarmed (See Table 2).   | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.  | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | <p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 Calendar Years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 Calendar Years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |



| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing Relay   |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |

| Table 4-2(a)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a <a href="#">SPS_RAS</a> |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a <a href="#">SPS_RAS</a> .   | 12 Calendar Years                 | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of a <a href="#">SPS_RAS</a> and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)           | No periodic maintenance specified | None.  |

| Table 4-2(b)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an <u>SPS_RAS</u> |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an <u>SPS_RAS</u> (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.   |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an <u>SPS_RAS</u> .   | 12 Calendar Years                 | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the <u>SPS_RAS</u> . |
| Control circuitry associated with Automatic Reclosing that is an integral part of an <u>SPS_RAS</u> whose integrity is monitored and alarmed. (See Table 2)   | No periodic maintenance specified | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-1(X)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
  - 4.1. Planning Coordinators
  - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - 4.2.1 Transmission Owners
    - 4.2.2 Distribution Providers
  - 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.
5. **(Proposed) Effective Date:**
  - 5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.
  - 5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1(X), but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1(X).

## B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [*VRF: Medium*][*Time Horizon: Long-term Planning*]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [*VRF: Medium*][*Time Horizon: Long-term Planning*]
  - 2.1. Those islands selected by applying the criteria in Requirement R1, and

- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme, and
  - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
- 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
    - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
    - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
    - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the

- Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
  - 11.1.** The performance of the UFLS equipment,
  - 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance



with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

**R14.** Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

**14.1.** UFLS program, including a schedule for implementation

**14.2.** UFLS design assessment

**14.3.** Format and schedule of UFLS data submittal

### **C. Measures**

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a

UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity

#### **1.2. Data Retention**

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

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

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

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

Not applicable.

**2. Violation Severity Levels**

| R #       | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----------|-----------|---|---|--|
| <b>R1</b> | N/A       | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>   |
| <b>R2</b> | N/A       | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p> |

| R #       | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
|-----------|--|---|--|--|
| <b>R3</b> | N/A  | <p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p> |
| <b>R4</b> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                        | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                     | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>   |

| R #       | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----------|--|--|--|---|
|           |  |  |  | <p>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2</p>                                 |
| <b>R5</b> | N/A  | N/A  | N/A  | <p>The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.</p> |
| <b>R6</b> | N/A  | N/A  | N/A  | <p>The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.</p>  |
| <b>R7</b> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.</p> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.</p> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.</p> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.<br/>OR</p>  |

| R #        | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL   |
|------------|---|--|---|--|
|            |   |  |   | The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.   |
| <b>R8</b>  | The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.                | The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. |
| <b>R9</b>  | The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. | The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   | The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.                  | The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   |
| <b>R10</b> | The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching  | The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching  | The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching   | The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,   |



| R #               | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-------------------|---|--|--|---|
|                   | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>   | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  | <p>Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  |
| <p><b>R11</b></p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.</p> <p>OR</p> |

| R #        | Lower VSL | Moderate VSL   | High VSL   | Severe VSL   |
|------------|-----------|--|--|--|
|            |           |  | specified in Requirement R11, Parts 11.1 or 11.2.  | The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.  |
| <b>R12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.<br><br>OR<br>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies. |
| <b>R13</b> | N/A       | N/A  | N/A  | The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency  |

| R #        | Lower VSL | Moderate VSL | High VSL | Severe VSL   |
|------------|-----------|--------------|----------|--|
|            |           |              |          | excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13   |
| <b>R14</b> | N/A       | N/A          | N/A      | The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3. |

## E. Regional Variances

### E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

- E.A.3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s).  
*[VRF: High][Time Horizon: Long-term Planning]*
- E.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
- EA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES
- EA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES
- EA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.
- E.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*
- E.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1A, and

**E.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 2A, and

**E.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**M.E.A.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

**M.E.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

| E #        | Lower VSL | Moderate VSL  | High VSL   | Severe VSL  |
|------------|-----------|---|--|---|
| <b>EA3</b> | N/A       | The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to develop a UFLS program.  |
| <b>EA4</b> | N/A       | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3.<br><br>OR<br><br>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 |

## **E.B. Regional Variance for the Western Electricity Coordinating Council**

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

- E.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*
- E.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*
  - E.B.2.1.** Those islands selected by applying the criteria in Requirement E.B.1, and
  - E.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme.
- EB.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*
  - E.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - E.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - E.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
    - E.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
    - E.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the



event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**E.B.11.1.** The performance of the UFLS equipment,

**E.B.11.2** The effectiveness of the UFLS program

**E.B.12.** Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

- M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.
- M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.
- M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.
- M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.
- M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.
- M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

| E #   | Lower VSL | Moderate VSL   | High VSL  | Severe VSL   |
|-------|-----------|--|---|--|
| E.B.1 | N/A       | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p> |
| E.B.2 | N/A       | N/A  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>   |

| E #          | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|--------------|---|--|--|--|
|              |   |  |  | <p>The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.</p>  |
| <b>E.B.3</b> | N/A   | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p> | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p> | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions</p> <p>OR</p> <p>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.</p> |
| <b>E.B.4</b> | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p> | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>                      | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>                      | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>  |

| E #           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|---------------|---|--|--|--|
|               | <p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>  | <p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p> |
| <b>E.B.11</b> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>   |

| E #           | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|---------------|-----------|---|---|--|
|               |           |   | <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p> | <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> |
| <b>E.B.12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design   | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design  |

| E # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
|     |           | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p> |

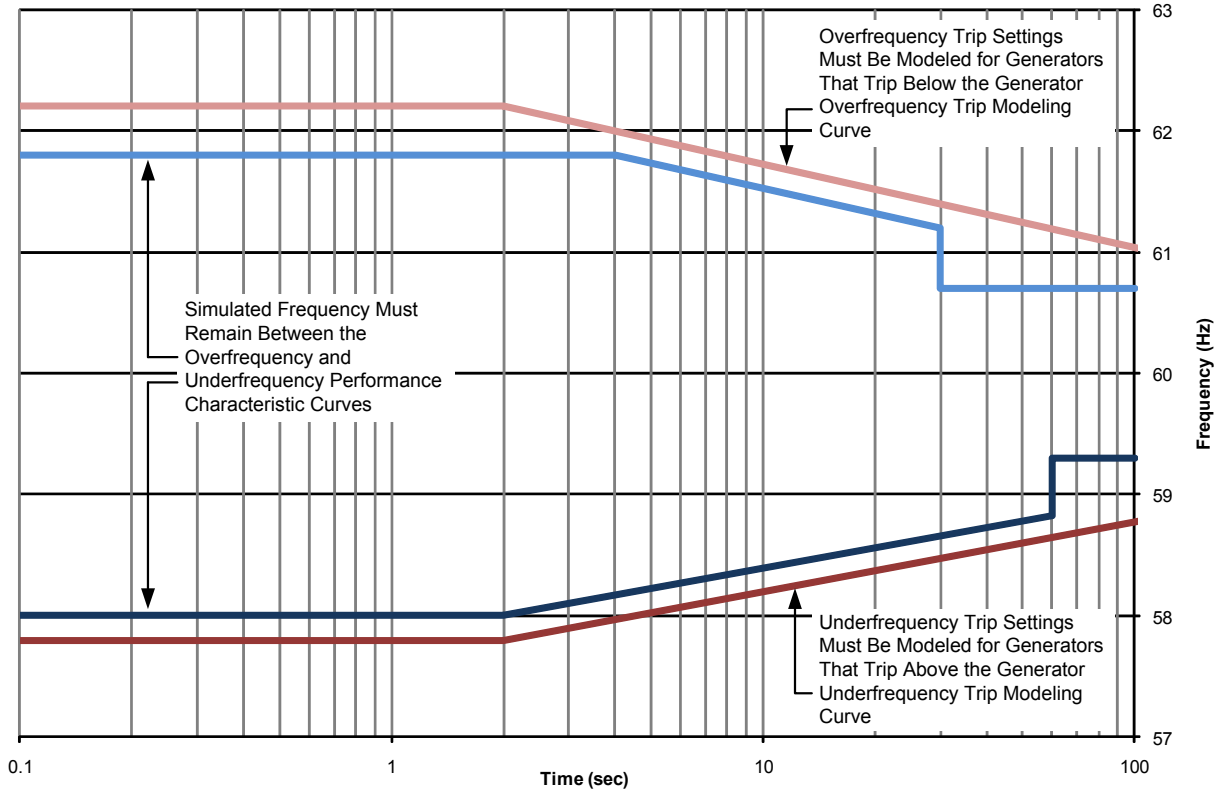
**Associated Documents**

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>  | <b>Change Tracking</b>   |
|----------------|------------------|--|--|
| 1              | May 25, 2010     | Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.   |  |
| 1              | November 4, 2010 | Adopted by the Board of Trustees   |  |
| 1              | May 7, 2012      | FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)   |  |
| 1              | November 9, 2012 | FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8. |  |
| 1(X)           | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## PRC-006-1(X) – Attachment 1

### Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



|      |   |
|------|---|
| □□□□ | Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)  |
| □□□□ | Overfrequency Performance Characteristic (Requirement R3 Part 3.2)    |
| □□□□ | Underfrequency Performance Characteristic (Requirement R3 Part 3.1)   |
| □□□□ | Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3) |

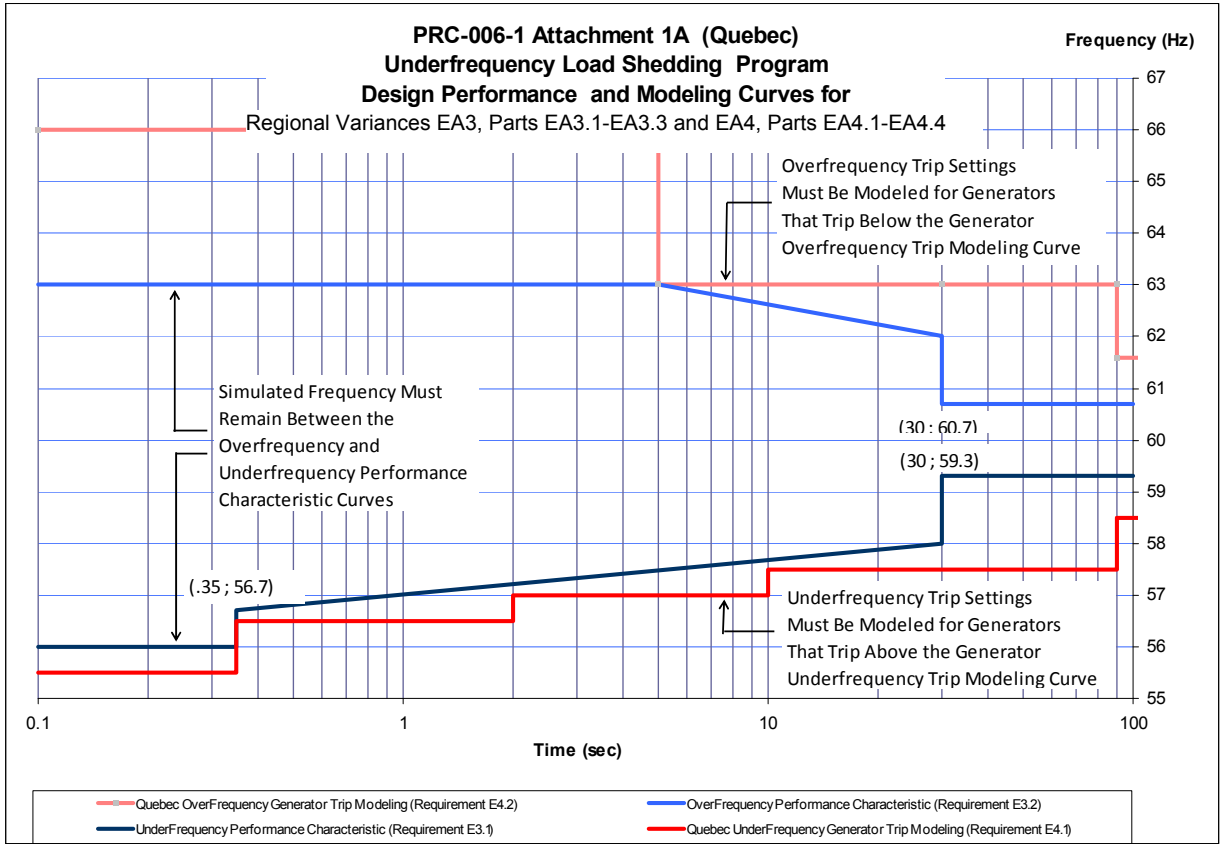
#### Curve Definitions

| Generator Overfrequency Trip Modeling |  | Overfrequency Performance Characteristic |  |                       |
|---------------------------------------|--|--|--|-----------------------|
| $t \leq 2 \text{ s}$                  | $t > 2 \text{ s}$                      | $t \leq 4 \text{ s}$                     | $4 \text{ s} < t \leq 30 \text{ s}$    | $t > 30 \text{ s}$    |
| $f = 62.2 \text{ Hz}$                 | $f = -0.686\log(t) + 62.41 \text{ Hz}$ | $f = 61.8 \text{ Hz}$                    | $f = -0.686\log(t) + 62.21 \text{ Hz}$ | $f = 60.7 \text{ Hz}$ |

| Generator Underfrequency Trip Modeling |                                       | Underfrequency Performance Characteristic |                                       |                       |
|--|---------------------------------------|---|---------------------------------------|-----------------------|
| $t \leq 2 \text{ s}$                   | $t > 2 \text{ s}$                     | $t \leq 2 \text{ s}$                      | $2 \text{ s} < t \leq 60 \text{ s}$   | $t > 60 \text{ s}$    |
| $f = 57.8 \text{ Hz}$                  | $f = 0.575\log(t) + 57.63 \text{ Hz}$ | $f = 58.0 \text{ Hz}$                     | $f = 0.575\log(t) + 57.83 \text{ Hz}$ | $f = 59.3 \text{ Hz}$ |







## A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-1(X)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
  - 4.1. Planning Coordinators
  - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - 4.2.1 Transmission Owners
    - 4.2.2 Distribution Providers
  - 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.
5. **(Proposed) Effective Date:**
  - 5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.
  - 5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1(X), but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1(X).

## B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [*VRF: Medium*][*Time Horizon: Long-term Planning*]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [*VRF: Medium*][*Time Horizon: Long-term Planning*]
  - 2.1. Those islands selected by applying the criteria in Requirement R1, and

- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or [Special Protection System Remedial Action Scheme](#), and
  - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
- 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
    - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
    - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
    - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the

- Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
- 11.1.** The performance of the UFLS equipment,
- 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance

with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

**R14.** Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

**14.1.** UFLS program, including a schedule for implementation

**14.2.** UFLS design assessment

**14.3.** Format and schedule of UFLS data submittal

### **C. Measures**

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a



UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity

#### **1.2. Data Retention**

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

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

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

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

Not applicable.

**2. Violation Severity Levels**

| R #       | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----------|-----------|---|---|--|
| <b>R1</b> | N/A       | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>   |
| <b>R2</b> | N/A       | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p> |

| R #       | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
|-----------|--|---|--|--|
| <b>R3</b> | N/A  | <p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p> |
| <b>R4</b> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                        | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                     | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>   |

| R #       | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----------|--|--|--|---|
|           |  |  |  | <p>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2</p>                                 |
| <b>R5</b> | N/A  | N/A  | N/A  | <p>The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.</p> |
| <b>R6</b> | N/A  | N/A  | N/A  | <p>The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.</p>  |
| <b>R7</b> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.</p> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.</p> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.</p> | <p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.<br/>OR</p>  |

| R #        | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL   |
|------------|---|--|---|--|
|            |   |  |   | The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.   |
| <b>R8</b>  | The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.                | The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. |
| <b>R9</b>  | The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. | The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   | The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.                  | The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   |
| <b>R10</b> | The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching  | The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching  | The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching   | The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,   |

| R #               | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-------------------|---|--|--|---|
|                   | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>   | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  | <p>Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  |
| <p><b>R11</b></p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.</p> <p>OR</p> |

| R #        | Lower VSL | Moderate VSL   | High VSL   | Severe VSL   |
|------------|-----------|--|--|--|
|            |           |  | specified in Requirement R11, Parts 11.1 or 11.2.  | The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.  |
| <b>R12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.<br><br>OR<br>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies. |
| <b>R13</b> | N/A       | N/A  | N/A  | The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency  |



| R #        | Lower VSL | Moderate VSL | High VSL | Severe VSL   |
|------------|-----------|--------------|----------|--|
|            |           |              |          | excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13   |
| <b>R14</b> | N/A       | N/A          | N/A      | The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3. |

## E. Regional Variances

### E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

- E.A.3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s).  
*[VRF: High][Time Horizon: Long-term Planning]*
- E.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
- EA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES
- EA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES
- EA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.
- E.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*
- E.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1A, and

- E.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 2A, and
  - E.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- M.E.A.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.
- M.E.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

| E #        | Lower VSL | Moderate VSL  | High VSL   | Severe VSL  |
|------------|-----------|---|--|---|
| <b>EA3</b> | N/A       | The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to develop a UFLS program.  |
| <b>EA4</b> | N/A       | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3.<br><br>OR<br><br>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 |

## **E.B. Regional Variance for the Western Electricity Coordinating Council**

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

**E.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.1.** Those islands selected by applying the criteria in Requirement E.B.1, and

**E.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or [Special Protection System Remedial Action Scheme](#).

**EB.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

**E.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**E.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

**E.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**E.B.11.1.** The performance of the UFLS equipment,

**E.B.11.2** The effectiveness of the UFLS program

**E.B.12.** Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

- M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.
- M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.
- M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.
- M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.
- M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.
- M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

| E #   | Lower VSL | Moderate VSL   | High VSL  | Severe VSL   |
|-------|-----------|--|---|--|
| E.B.1 | N/A       | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p> |
| E.B.2 | N/A       | N/A  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>   |



| E #          | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|--------------|---|--|--|--|
|              |   |  |  | <p>The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.</p>  |
| <b>E.B.3</b> | N/A   | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p> | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p> | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions</p> <p>OR</p> <p>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.</p> |
| <b>E.B.4</b> | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p> | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>                      | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>                      | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>  |

| E #           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|---------------|---|--|--|--|
|               | <p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>  | <p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p> |
| <b>E.B.11</b> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>   |

| E #           | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|---------------|-----------|---|---|--|
|               |           |   | <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p> | <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> |
| <b>E.B.12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design   | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design  |

| E # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
|     |           | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p> |

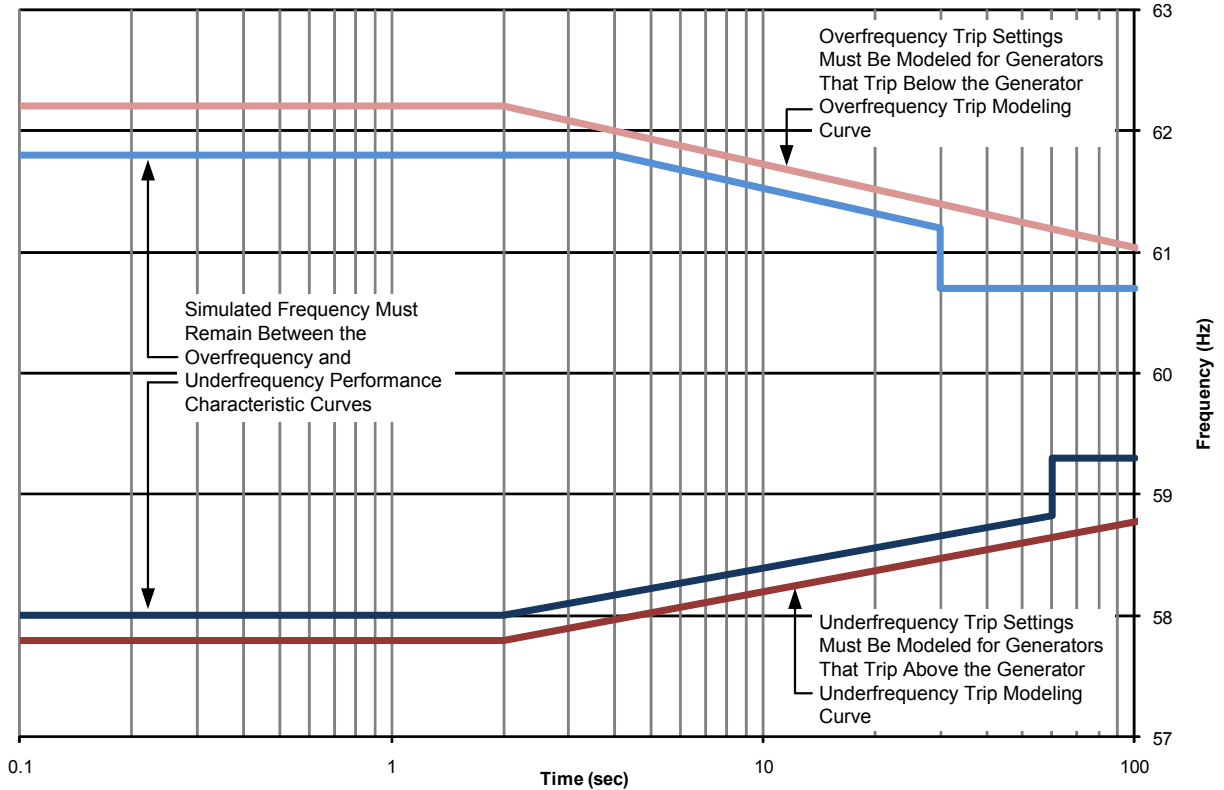
**Associated Documents**

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>  | <b>Change Tracking</b>  |
|----------------|------------------|--|---|
| 1              | May 25, 2010     | Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.   |   |
| 1              | November 4, 2010 | Adopted by the Board of Trustees   |   |
| 1              | May 7, 2012      | FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)   |   |
| 1              | November 9, 2012 | FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8. |   |
| <u>1(X)</u>    | <u>TBD</u>       | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## PRC-006-1(X) – Attachment 1

### Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



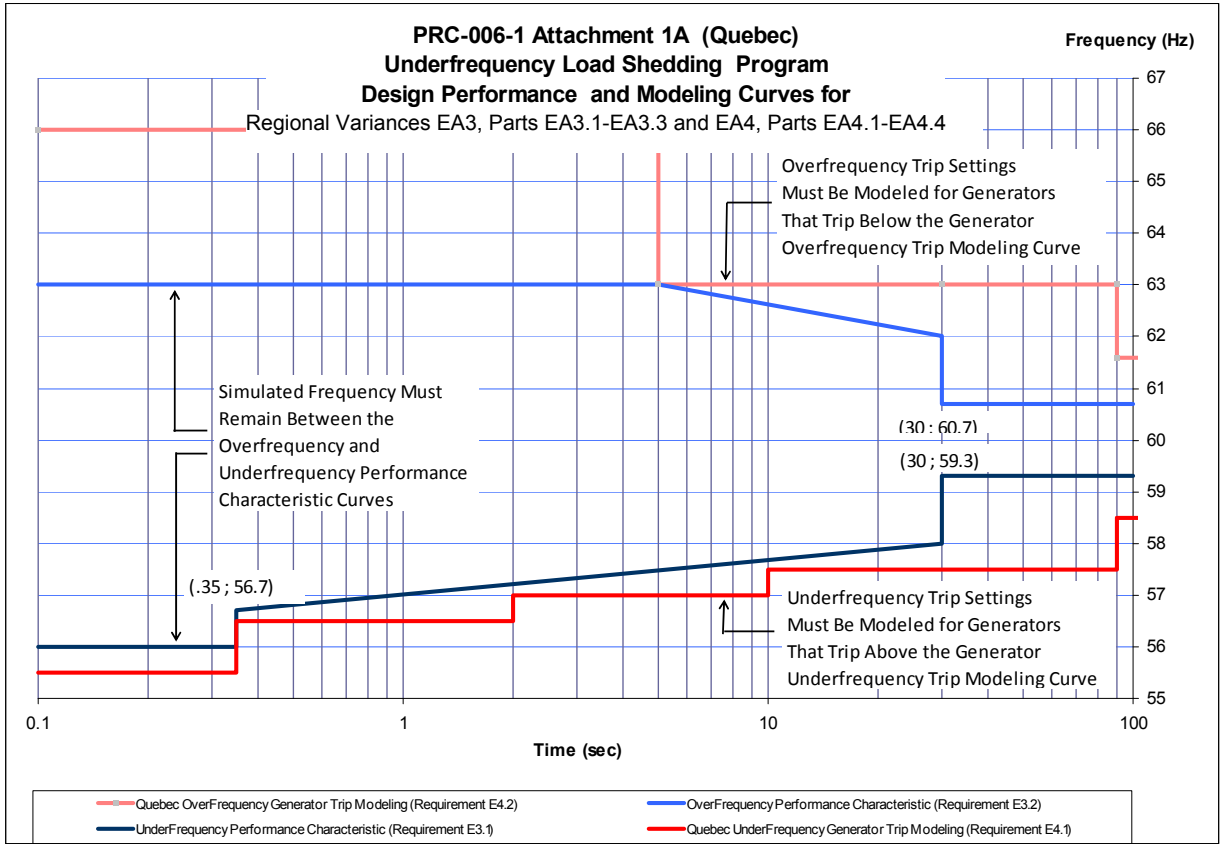
|      |   |
|------|---|
| □□□□ | Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)  |
| □□□□ | Overfrequency Performance Characteristic (Requirement R3 Part 3.2)    |
| □□□□ | Underfrequency Performance Characteristic (Requirement R3 Part 3.1)   |
| □□□□ | Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3) |

#### Curve Definitions

| Generator Overfrequency Trip Modeling |  | Overfrequency Performance Characteristic |  |                       |
|---------------------------------------|--|--|--|-----------------------|
| $t \leq 2 \text{ s}$                  | $t > 2 \text{ s}$                      | $t \leq 4 \text{ s}$                     | $4 \text{ s} < t \leq 30 \text{ s}$    | $t > 30 \text{ s}$    |
| $f = 62.2 \text{ Hz}$                 | $f = -0.686\log(t) + 62.41 \text{ Hz}$ | $f = 61.8 \text{ Hz}$                    | $f = -0.686\log(t) + 62.21 \text{ Hz}$ | $f = 60.7 \text{ Hz}$ |

| Generator Underfrequency Trip Modeling |                                       | Underfrequency Performance Characteristic |                                       |                       |
|--|---------------------------------------|---|---------------------------------------|-----------------------|
| $t \leq 2 \text{ s}$                   | $t > 2 \text{ s}$                     | $t \leq 2 \text{ s}$                      | $2 \text{ s} < t \leq 60 \text{ s}$   | $t > 60 \text{ s}$    |
| $f = 57.8 \text{ Hz}$                  | $f = 0.575\log(t) + 57.63 \text{ Hz}$ | $f = 58.0 \text{ Hz}$                     | $f = 0.575\log(t) + 57.83 \text{ Hz}$ | $f = 59.3 \text{ Hz}$ |







**A. Introduction**

- 1. Title:** Remedial Action Scheme Review Procedure
- 2. Number:** PRC-012-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Regional Reliability Organization
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:
  - R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review.
  - R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS.
  - R1.3.** Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4.** Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6.** Regional Reliability Organization definition of misoperation.
  - R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations.
  - R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9.** Determination, as appropriate, of maintenance and testing requirements.
- R2.** The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**C. Measures**

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0(X)\_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0(X)\_R1.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| <b>Version</b> | <b>Date</b>   | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|---------------|---------------------------------------|--|
| 0              | April 1, 2005 | Effective Date                        | New  |
| 0(X)           | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard PRC-012-0(X) — ~~Special Protection System~~ Remedial Action Scheme Review Procedure

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### A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Review Procedure
2. **Number:** PRC-012-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

### B. Requirements

- R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a ~~n-SPS RAS~~ shall have a documented Regional Reliability Organization ~~SPSRAS~~ review procedure to ensure that ~~SPSRAS~~s comply with Regional criteria and NERC Reliability Standards. The Regional ~~SPSRAS~~ review procedure shall include:
  - R1.1. Description of the process for submitting a proposed ~~SPSRAS~~ for Regional Reliability Organization review.
  - R1.2. Requirements to provide data that describes design, operation, and modeling of a ~~n-SPSRAS~~.
  - R1.3. Requirements to demonstrate that the ~~SPSRAS~~ shall be designed so that a single ~~SPSRAS~~ component failure, when the ~~SPSRAS~~ was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4. Requirements to demonstrate that the inadvertent operation of a ~~n-SPSRAS~~ shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5. Requirements to demonstrate the proposed ~~SPSRAS~~ will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6. Regional Reliability Organization definition of misoperation.
  - R1.7. Requirements for analysis and documentation of corrective action plans for all ~~SPSRAS~~ misoperations.
  - R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9. Determination, as appropriate, of maintenance and testing requirements.
- R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its ~~SPSRAS~~ review procedure on request (within 30 calendar days).



## Standard PRC-012-0(X) — ~~Special Protection System~~ Remedial Action Scheme Review Procedure

### C. Measures

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use an ~~SPS RAS~~ shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0(X)\_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its ~~SPSRAS~~ review procedure on request (within 30 calendar days).

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

##### 1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

##### 1.3. Data Retention

None specified.

##### 1.4. Additional Compliance Information

None.

#### 2. Levels of Non-Compliance

- 2.1. Level 1:** Documentation of the Regional Reliability Organization's procedure is missing one of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization's procedure is missing two of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization's procedure is missing three of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization's procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0(X)\_R1.

### E. Regional Differences

1. None identified.

### Version History

| Version     | Date          | Action                                       | Change Tracking   |
|-------------|---------------|--|---|
| 0           | April 1, 2005 | Effective Date                               | New   |
| <u>0(X)</u> | <u>TBD</u>    | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |
|             |               |  |   |

Standard PRC-012-0(X) — ~~Special Protection System~~ Remedial Action Scheme Review Procedure

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|--|--|--|--|

## A. Introduction

1. **Title:** Remedial Action Scheme Database.
2. **Number:** PRC-013-0(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

## B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,
  - R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

## C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-0(X)\_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
  - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
  - 1.3. **Data Retention**

None specified.
  - 1.4. **Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-0(X)\_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-0(X)\_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0(X)\_R1.

**E. Regional Differences**

- 1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>   | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|---------------|---------------------------------------|--|
| 0              | April 1, 2005 | Effective Dave                        | New  |
| 0(X)           | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|                |               |                                       |  |
|                |               |                                       |  |



## A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Database.
2. **Number:** PRC-013-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPSs)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

## B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a ~~an SPS RAS~~ installed shall maintain a ~~an SPS RAS~~ database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the ~~SPSRAS~~ was designed,
  - R1.2. Operation — The actions taken by the ~~SPSRAS~~ in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the ~~SPSRAS~~.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

## C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a ~~an SPS RAS~~ installed, shall have a ~~an SPS RAS~~ database as defined in PRC-013-0(X)\_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
  - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
  - 1.3. **Data Retention**

None specified.
  - 1.4. **Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-0(X)\_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-0(X)9\_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0(X)\_R1.

**E. Regional Differences**

- 1. None identified.

**Version History**

| Version     | Date          | Action                                       | Change Tracking   |
|-------------|---------------|--|---|
| 0           | April 1, 2005 | Effective Dave                               | New   |
| <u>0(X)</u> | <u>TBD</u>    | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |
|             |               |  |   |
|             |               |  |   |

**A. Introduction**

- 1. Title:** Remedial Action Scheme Assessment
- 2. Number:** PRC-014-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Regional Reliability Organization
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3.** The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:
  - R3.1.** Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems.
  - R3.5.** Provide corrective action plans for non-compliant RAS.

**C. Measures**

- M1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3.** The Regional Reliability Organization's documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-0(X)\_R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-0(X)\_R3.

**2.2. Level 2:** The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-0(X)\_3.

**2.3. Level 3:** The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-0(X)\_R3.

**2.4. Level 4:** The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-0(X)\_R3 or was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|         |               |                                       |  |
|         |               |                                       |  |

## A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Assessment
2. **Number:** PRC-014-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

## B. Requirements

- R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all ~~SPSRAS~~s installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all ~~SPSRAS~~s installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3. The documentation of the Regional Reliability Organization's ~~SPSRAS~~ assessment shall include the following elements:
  - R3.1. Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3. Identification of ~~SPSRAS~~s that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4. Discussion of any coordination problems found between a ~~SPSRAS~~ and other protection and control systems.
  - R3.5. Provide corrective action plans for non-compliant ~~SPSRAS~~s.

## C. Measures

- M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all ~~SPSRAS~~s installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3. The Regional Reliability Organization's documentation of the ~~SPSRAS~~ assessment shall include all elements as defined in Reliability Standard PRC-014-0(X)\_R3.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

#### 1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

#### 1.3. Data Retention

None specified.

#### 1.4. Additional Compliance Information

None.

### 2. Levels of Non-Compliance

**2.1. Level 1:** The summary (or detailed) Regional [SPSRAS](#) assessment is missing one of the items listed in Reliability Standard PRC-014-0(X)\_R3.

**2.2. Level 2:** The summary (or detailed) Regional [SPSRAS](#) assessment is missing two of the items listed in Reliability Standard PRC-014-0(X)\_3.

**2.3. Level 3:** The summary (or detailed) Regional [SPSRAS](#) assessment is missing three of the items listed in Reliability Standard PRC-014-0(X)\_R3.

**2.4. Level 4:** The summary (or detailed) Regional [SPSRAS](#) assessment is missing more than three of the items listed in Reliability Standard PRC-014-0(X)\_R3 or was not provided.

## E. Regional Differences

- None identified.

## Version History

| Version         | Date           | Action   | Change Tracking   |
|-----------------|----------------|--|---|
| 0               | April 1, 2005  | Effective Date                                   | New   |
| <del>0(X)</del> | <del>TBD</del> | <del>Adopted by the NERC Board of Trustees</del> | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |
|                 |                |  |   |
|                 |                |  |   |

**A. Introduction**

- 1. Title:** Remedial Action Scheme Data and Documentation
- 2. Number:** PRC-015-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Transmission Owner that owns a RAS
  - 4.2.** Generator Owner that owns a RAS
  - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-0(X)\_R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

**C. Measures**

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-0(X)\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

**2.2. Level 2:** RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-0(X)\_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## Standard PRC-015-0(X) — ~~Special Protection System~~ Remedial Action Scheme Data and Documentation

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### A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Data and Documentation
2. **Number:** PRC-015-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns an ~~SPS~~ RAS
  - 4.2. Generator Owner that owns an ~~SPS~~ RAS
  - 4.3. Distribution Provider that owns an ~~SPS~~ RAS
5. **Effective Date:** April 1, 2005

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall maintain a list of and provide data for existing and proposed ~~SPS~~RASs as specified in Reliability Standard PRC-013-0(X)\_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have evidence it reviewed new or functionally modified ~~SPS~~RASs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall provide documentation of ~~SPS~~RAS data and the results of Studies that show compliance of new or functionally modified ~~SPS~~RASs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall have evidence it maintains a list of and provides data for existing and proposed ~~SPS~~RASs as defined in Reliability Standard PRC-013-0(X)\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall have evidence it reviewed new or functionally modified ~~SPS~~RASs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall have evidence it provided documentation of ~~SPS~~RAS data and the results of studies that show compliance of new or functionally modified ~~SPS~~RASs with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

### D. Compliance

1. **Compliance Monitoring Process**

**Standard PRC-015-0(X) — ~~Special Protection System~~ Remedial Action Scheme Data and Documentation**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** [SPSRAS](#) owners provided [SPSRAS](#) data, but was incomplete according to the Regional Reliability Organization [SPSRAS](#) database requirements.

**2.2. Level 2:** [SPSRAS](#) owners provided results of studies that show compliance of new or functionally modified [SPSRASs](#) with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No [SPSRAS](#) data was provided in accordance with Regional Reliability Organization [SPSRAS](#) database requirements for Standard PRC-012-0(X)\_R1, or the results of studies that show compliance of new or functionally modified [SPSRASs](#) with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

**E. Regional Differences**

- None identified.

**Version History**

| Version         | Date           | Action   | Change Tracking   |
|-----------------|----------------|--|---|
| 0               | April 1, 2005  | Effective Date                                   | New   |
| <del>0(X)</del> | <del>TBD</del> | <del>Adopted by the NERC Board of Trustees</del> | <del>Replaced references to <a href="#">Special Protection System and SPS with Remedial Action Scheme and RAS</a></del> |
|                 |                |  |   |
|                 |                |  |   |

### A. Introduction

1. **Title: Remedial Action Scheme Misoperations**
2. **Number:** PRC-016-0.1(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS.
  - 4.2. Generator Owner that owns a RAS.
  - 4.3. Distribution Provider that owns a RAS.
5. **Effective Date:** May 13, 2009

### B. Requirements

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

### C. Measures

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

## Standard PRC-016-0.1(X) — Remedial Action Scheme Misoperations

### 1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

**2.2. Level 2:** Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

**2.3. Level 3:** Documentation of RAS misoperations and corrective actions is incomplete.

**2.4. Level 4:** No documentation of RAS misoperations or corrective actions.

## E. Regional Differences

None identified.

## Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 0       | April 1, 2005    | Effective Date   | New  |
| 0       | February 8, 2005 | Adopted by NERC Board of Trustees                                    | New  |
| 0       | July 3, 2007     | Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.” | Errata   |
| 0.1     | October 29, 2008 | BOT adopted errata changes; updated version number to “0.1”          | Errata   |
| 0.1     | May 13, 2009     | FERC Approved – Updated Effective Date                               | Revised  |
| 0.1(X)  | TBD              | Adopted by the NERC Board of Trustees                                | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

# Standard PRC-016-0.1(X) — ~~Special Protection System~~ Remedial Action Scheme Misoperations

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## A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Misoperations
2. **Number:** PRC-016-0.1(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a ~~an SPS~~ RAS.
  - 4.2. Generator Owner that owns a ~~an SPS~~ RAS.
  - 4.3. Distribution Provider that owns a ~~an SPS~~ RAS.
5. **Effective Date:** May 13, 2009

## B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an SPS~~ RAS shall analyze its ~~SPSRAS~~ operations and maintain a record of all misoperations in accordance with the Regional ~~SPSRAS~~ review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an SPS~~ RAS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an SPS~~ RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

## C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an SPS~~ RAS shall have evidence it analyzed ~~SPSRAS~~ operations and maintained a record of all misoperations in accordance with the Regional ~~SPSRAS~~ review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an SPS~~ RAS shall have evidence it took corrective actions to avoid future misoperations.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an SPS~~ RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

**Standard PRC-016-0.1(X) — ~~Special Protection System~~ Remedial Action Scheme Misoperations**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of [SPSRAS](#) misoperations is complete but documentation of corrective actions taken for all identified [SPSRAS](#) misoperations is incomplete.

**2.2. Level 2:** Documentation of corrective actions taken for [SPSRAS](#) misoperations is complete but documentation of [SPSRAS](#) misoperations is incomplete.

**2.3. Level 3:** Documentation of [SPSRAS](#) misoperations and corrective actions is incomplete.

**2.4. Level 4:** No documentation of [SPSRAS](#) misoperations or corrective actions.

**E. Regional Differences**

None identified.

**Version History**

| Version                | Date                | Action   | Change Tracking   |
|------------------------|---------------------|--|---|
| 0                      | April 1, 2005       | Effective Date   | New   |
| 0                      | February 8, 2005    | Adopted by NERC Board of Trustees                                    | New   |
| 0                      | July 3, 2007        | Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.” | Errata  |
| 0.1                    | October 29, 2008    | BOT adopted errata changes; updated version number to “0.1”          | Errata  |
| 0.1                    | May 13, 2009        | FERC Approved – Updated Effective Date                               | Revised   |
| <a href="#">0.1(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>                | <a href="#">Replaced references to Special Protection</a> |

Standard PRC-016-0.1(X) — ~~Special Protection System~~ Remedial Action Scheme  
Misoperations

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|  |  |  |   |
|--|--|--|---|
|  |  |  | <u>System and SPS with Remedial Action Scheme and RAS</u> |
|--|--|--|---|

**A. Introduction**

- 1. Title:** Remedial Action Scheme Maintenance and Testing
- 2. Number:** PRC-017-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Transmission Owner that owns a RAS
  - 4.2.** Generator Owner that owns a RAS
  - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1.** RAS identification shall include but is not limited to:
    - R1.1.1.** Relays.
    - R1.1.2.** Instrument transformers.
    - R1.1.3.** Communications systems, where appropriate.
    - R1.1.4.** Batteries.
  - R1.2.** Documentation of maintenance and testing intervals and their basis.
  - R1.3.** Summary of testing procedure.
  - R1.4.** Schedule for system testing.
  - R1.5.** Schedule for system maintenance.
  - R1.6.** Date last tested/maintained.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**C. Measures**

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0(X)\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).



**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

**1.2. Compliance Monitoring Period and Reset Timeframe**

Compliance Monitor: Regional Reliability Organization.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard PRC-017-0(X) — ~~Special Protection System~~ Remedial Action Scheme Maintenance and Testing

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### A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Maintenance and Testing
2. **Number:** PRC-017-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns an ~~SPS~~ RAS
  - 4.2. Generator Owner that owns an ~~SPS~~ RAS
  - 4.3. Distribution Provider that owns an ~~SPS~~ RAS
5. **Effective Date:** April 1, 2005

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1. ~~SPS~~RAS identification shall include but is not limited to:
    - R1.1.1. Relays.
    - R1.1.2. Instrument transformers.
    - R1.1.3. Communications systems, where appropriate.
    - R1.1.4. Batteries.
  - R1.2. Documentation of maintenance and testing intervals and their basis.
  - R1.3. Summary of testing procedure.
  - R1.4. Schedule for system testing.
  - R1.5. Schedule for system maintenance.
  - R1.6. Date last tested/maintained.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0(X)\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

#### Timeframe:

On request (30 calendar days.)

#### 1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitor: Regional Reliability Organization.

#### 1.3. Data Retention

None specified.

#### 1.4. Additional Compliance Information

None.

### 2. Levels of Non-Compliance

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

## E. Regional Differences

- None identified.

## Version History

| Version         | Date           | Action   | Change Tracking   |
|-----------------|----------------|--|---|
| 0               | April 1, 2005  | Effective Date                                   | New   |
| <del>0(X)</del> | <del>TBD</del> | <del>Adopted by the NERC Board of Trustees</del> | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |

**A. Introduction**

1. **Title:** Under-Voltage Load Shedding Program Database
2. **Number:** PRC-020-1(X)
3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
4. **Applicability**
  - 4.1. Regional Reliability Organization with entities that own or operate a UVLS program.
5. **Effective Date:** May 1, 2006

**B. Requirements**

- R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
  - R1.1. Owner and operator of the UVLS program.
  - R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.3. Corresponding voltage set points and overall scheme clearing times.
  - R1.4. Time delay from initiation to trip signal.
  - R1.5. Breaker operating times.
  - R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

**C. Measures**

- M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

**D. Compliance**

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

NERC
  - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. **Data Retention**

## Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

2.1. **Level 1:** Did not update its UVLS database annually.

2.2. **Level 2:** UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Did not provide information from its UVLS program database.

## E. Regional Differences

None identified.

## Version History

| Version | Date     | Action  | Change Tracking  |
|---------|----------|---|--|
| 1       | 12/01/05 | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—).”</li> <li>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>4. Added or removed “periods” where appropriate.</li> <li>5. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/06   |
| 1(X)    | TBD      | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

# Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

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## A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Database
2. **Number:** PRC-020-1(X)
3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
4. **Applicability**
  - 4.1. Regional Reliability Organization with entities that own or operate a UVLS program.
5. **Effective Date:** May 1, 2006

## B. Requirements

- R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
  - R1.1. Owner and operator of the UVLS program.
  - R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.3. Corresponding voltage set points and overall scheme clearing times.
  - R1.4. Time delay from initiation to trip signal.
  - R1.5. Breaker operating times.
  - R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and [Special Protection System Remedial Action Schemes](#).
- R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

## C. Measures

- M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

NERC
  - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. **Data Retention**

## Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

2.1. **Level 1:** Did not update its UVLS database annually.

2.2. **Level 2:** UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Did not provide information from its UVLS program database.

## E. Regional Differences

None identified.

## Version History

| Version     | Date       | Action  | Change Tracking   |
|-------------|------------|---|---|
| 1           | 12/01/05   | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—).”</li> <li>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>4. Added or removed “periods” where appropriate.</li> <li>5. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/06  |
| <u>1(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

- 1. Title:** Under-Voltage Load Shedding Program Data
- 2. Number:** PRC-021-1(X)
- 3. Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
- 4. Applicability**
  - 4.1.** Transmission Owner that owns a UVLS program.
  - 4.2.** Distribution Provider that owns a UVLS program.
- 5. Effective Date:** August 1, 2006

**B. Requirements**

- R1.** Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
  - R1.1.** Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.2.** Corresponding voltage set points and overall scheme clearing times.
  - R1.3.** Time delay from initiation to trip signal.
  - R1.4.** Breaker operating times.
  - R1.5.** Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2.** Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

**C. Measures**

- M1.** Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2.** Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.
  - 1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. Data Retention**



## Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Did not update its UVLS data annually.

**2.2. Level 2:** UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

**2.3. Level 3:** UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

**2.4. Level 4:** Did not provide any UVLS data.

## E. Regional Differences

None identified.

## Version History

| Version | Date     | Action  | Change Tracking  |
|---------|----------|---|--|
| 1       | 12/01/05 | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>3. Added heading above table “Future Development Plan.”</li> <li>4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>5. Added or removed “periods” where appropriate.</li> <li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05   |
| 1(X)    | TBD      | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** Under-Voltage Load Shedding Program Data
2. **Number:** PRC-021-1(X)
3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. **Applicability**
  - 4.1. Transmission Owner that owns a UVLS program.
  - 4.2. Distribution Provider that owns a UVLS program.
5. **Effective Date:** August 1, 2006

**B. Requirements**

- R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
  - R1.1. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.2. Corresponding voltage set points and overall scheme clearing times.
  - R1.3. Time delay from initiation to trip signal.
  - R1.4. Breaker operating times.
  - R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and [Special Protection System Remedial Action Schemes](#).
- R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

**C. Measures**

- M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

**D. Compliance**

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.
  - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. **Data Retention**

## Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Did not update its UVLS data annually.

**2.2. Level 2:** UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

**2.3. Level 3:** UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

**2.4. Level 4:** Did not provide any UVLS data.

## E. Regional Differences

None identified.

## Version History

| Version     | Date       | Action  | Change Tracking   |
|-------------|------------|---|---|
| 1           | 12/01/05   | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>3. Added heading above table “Future Development Plan.”</li> <li>4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>5. Added or removed “periods” where appropriate.</li> <li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05  |
| <u>1(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

### A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-2(X)

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability**

**4.1. Functional Entity**

**4.1.1** Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

**4.1.2** Generator Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

**4.1.3** Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

**4.1.4** Planning Coordinators

**4.2. Circuits**

**4.2.1 Circuits Subject to Requirements R1 – R5**

**4.2.1.1** Transmission lines operated at 200 kV and above.

**4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

**4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

**4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above.

**4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

**4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

**4.2.2 Circuits Subject to Requirement R6**

**4.2.2.1** Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

**5. Effective Dates**

The effective dates of the requirements in the PRC-023-2(X) standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

**Standard PRC-023-2(X) — Transmission Relay Loadability**

| Requirement | Applicability  | Effective Date   |   |
|-------------|--|--|---|
|             |  | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required  |
| R1          | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.  | First day of the first calendar quarter, after applicable regulatory approvals   | First calendar quarter after Board of Trustees adoption   |
|             | <ul style="list-style-type: none"> <li>For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability</li> </ul> | First day of the first calendar quarter 12 months after applicable regulatory approvals  | First day of the first calendar quarter 12 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For supervisory elements as described in PRC-023-2(X) - Attachment A, Section 1.6</li> </ul>  | First day of the first calendar quarter 24 months after applicable regulatory approvals  | First day of the first calendar quarter 24 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For switch-on-to-fault schemes as described in PRC-023-2(X) - Attachment A, Section 1.3</li> </ul>  | Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2(X) or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013) | Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2(X) or July 1, 2011 <sup>1</sup>            |
|             | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on |

<sup>1</sup> July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

**Standard PRC-023-2(X) — Transmission Relay Loadability**

| Requirement      | Applicability   | Effective Date   |  |
|------------------|---|--|--|
|                  |   | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required   |
|                  |   | list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   | a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   |
|                  |   |  |  |
| <b>R2 and R3</b> | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above | First day of the first calendar quarter after applicable regulatory approvals  | First day of the first calendar quarter after Board of Trustees adoption   |
|                  | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6   | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date |

**Standard PRC-023-2(X) — Transmission Relay Loadability**

| Requirement | Applicability   | Effective Date   |   |
|-------------|---|--|---|
|             |   | Jurisdictions where Regulatory Approval is Required                                      | Jurisdictions where No Regulatory Approval is Required                              |
| <b>R4</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R5</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R6</b>   | Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5 | First day of the first calendar quarter 18 months after applicable regulatory approvals  | First day of the first calendar quarter 18 months after Board of Trustees adoption  |

**B. Requirements**

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

**Criteria:**

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>2</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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<sup>2</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.



8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>3</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>4</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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<sup>3</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

<sup>4</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(X) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>   |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>   |

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| Requirement | Lower | Moderate   | High   | Severe   |
|-------------|-------|--|--|--|
|             |       |  |  | The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.<br><br>OR<br><br>The Planning Coordinator used the criteria established within   |

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| Requirement | Lower | Moderate  | High   | Severe   |
|-------------|-------|---|--|--|
|             |       | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p> |

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| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
|             |       |          |      | <p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |



**E. Regional Differences**

None

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking  |
|---------|--|---|--|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New  |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata   |
| 1       | March 18, 2010                               | Approved by FERC  |  |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision   |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)   |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |  |
| 2(X)    | TBD  | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023 — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Generator protection relays that are susceptible to load.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

**PRC-023 — Attachment B**

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>5</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>5</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

### A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-2(X)

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability**

**4.1. Functional Entity**

**4.1.1** Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

**4.1.2** Generator Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

**4.1.3** Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

**4.1.4** Planning Coordinators

**4.2. Circuits**

**4.2.1 Circuits Subject to Requirements R1 – R5**

**4.2.1.1** Transmission lines operated at 200 kV and above.

**4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

**4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

**4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above.

**4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

**4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

**4.2.2 Circuits Subject to Requirement R6**

**4.2.2.1** Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

**5. Effective Dates**

The effective dates of the requirements in the PRC-023-2(X) standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

**Standard PRC-023-2(X) — Transmission Relay Loadability**

| Requirement | Applicability  | Effective Date   |   |
|-------------|--|--|---|
|             |  | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required  |
| R1          | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.  | First day of the first calendar quarter, after applicable regulatory approvals   | First calendar quarter after Board of Trustees adoption   |
|             | <ul style="list-style-type: none"> <li>For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability</li> </ul> | First day of the first calendar quarter 12 months after applicable regulatory approvals  | First day of the first calendar quarter 12 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For supervisory elements as described in PRC-023-2(X) - Attachment A, Section 1.6</li> </ul>  | First day of the first calendar quarter 24 months after applicable regulatory approvals  | First day of the first calendar quarter 24 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For switch-on-to-fault schemes as described in PRC-023-2(X) - Attachment A, Section 1.3</li> </ul>  | Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2(X) or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013) | Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2(X) or July 1, 2011 <sup>1</sup>            |
|             | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on |

<sup>1</sup> July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

**Standard PRC-023-2(X) — Transmission Relay Loadability**

| Requirement      | Applicability   | Effective Date   |  |
|------------------|---|--|--|
|                  |   | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required   |
|                  |   | list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   | a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   |
|                  |   |  |  |
| <b>R2 and R3</b> | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above | First day of the first calendar quarter after applicable regulatory approvals  | First day of the first calendar quarter after Board of Trustees adoption   |
|                  | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6   | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date |

**Standard PRC-023-2(X) — Transmission Relay Loadability**

| Requirement | Applicability   | Effective Date   |   |
|-------------|---|--|---|
|             |   | Jurisdictions where Regulatory Approval is Required                                      | Jurisdictions where No Regulatory Approval is Required                              |
| <b>R4</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R5</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R6</b>   | Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5 | First day of the first calendar quarter 18 months after applicable regulatory approvals  | First day of the first calendar quarter 18 months after Board of Trustees adoption  |



**B. Requirements**

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

**Criteria:**

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>2</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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<sup>2</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>3</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>4</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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<sup>3</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

<sup>4</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(X) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>   |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>   |

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| Requirement | Lower | Moderate   | High   | Severe   |
|-------------|-------|--|--|--|
|             |       |  |  | The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.<br><br>OR<br><br>The Planning Coordinator used the criteria established within   |

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| Requirement | Lower | Moderate  | High   | Severe   |
|-------------|-------|---|--|--|
|             |       | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p> |



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| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
|             |       |          |      | <p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version          | Date   | Action  | Change Tracking   |
|------------------|--|---|---|
| 1                | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1                | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1                | March 18, 2010                               | Approved by FERC  |   |
| 1                | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2                | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2                | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| <del>2</del> (X) | <del>TBD</del>                               | <del>Adopted by the NERC Board of Trustees</del>  | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |

**PRC-023 — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Generator protection relays that are susceptible to load.
  - 2.5. Relay elements used only for ~~Special Protection System~~ Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

**PRC-023 — Attachment B**

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>5</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>5</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
    - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
    - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
  - e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

## A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-3(X)
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
  - 4.1. **Functional Entity:**
    - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinator
  - 4.2. **Circuits:**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 **Circuits Subject to Requirement R6:**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**5. Effective Dates:** See Implementation Plan.

## **B. Requirements**

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

### **Criteria:**

- 1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
- 2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
- 3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
- 4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
- 5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
- 6.** Not used.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.



- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-3(X) per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3(X), Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### **C. Measures**

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
|             |       |  |  | <p>OR</p> <p>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.</p>  |
| <b>R4</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.</p> |
| <b>R5</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.</p>  |
| <b>R6</b>   | N/A   | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more</p> | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24</p> | <p>The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>  |

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| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

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| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
|             |       | <p>the list was established or updated. (part 6.2)</p> |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None.

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |



**Standard PRC-023-3(X) — Transmission Relay Loadability**

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| Version | Date | Action                                | Change Tracking  |
|---------|------|---------------------------------------|--|
| 3(X)    | TBD  | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023-3(X) — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

**PRC-023-3(X) — Attachment B**

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-3(X) — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
    - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
    - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
  - e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

## A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-3(X)
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
  - 4.1. **Functional Entity:**
    - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinator
  - 4.2. **Circuits:**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 **Circuits Subject to Requirement R6:**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**5. Effective Dates:** See Implementation Plan.

## **B. Requirements**

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

### **Criteria:**

- 1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
- 2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
- 3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
- 4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
- 5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
- 6.** Not used.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-3(X) per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3(X), Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### **C. Measures**

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)



- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
|             |       |  |  | <p>OR</p> <p>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.</p>  |
| <b>R4</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.</p> |
| <b>R5</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.</p>  |
| <b>R6</b>   | N/A   | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more</p> | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24</p> | <p>The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>  |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
|             |       | <p>the list was established or updated. (part 6.2)</p> |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None.

**F. Supplemental Technical Reference Document**

- The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |

Standard PRC-023-3(X) — Transmission Relay Loadability

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| Version     | Date       | Action                                       | Change Tracking   |
|-------------|------------|--|---|
| <u>3(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |



**PRC-023-3(X) — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for [Special Protection System Remedial Action Schemes](#) applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

PRC-023-3(X) — Attachment B

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-3(X) — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

**A. Introduction**

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-1(X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
  - 4.1. Generator Owner
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required:
    - 5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
  - 5.2. In those jurisdictions where regulatory approval is not required:
    - 5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- 5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
- 5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

## **B. Requirements**

- R1.** Each Generator Owner that has generator frequency protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
  - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
  - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection<sup>2</sup>) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip in accordance with a Remedial Action Scheme (RAS).
  - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
  - Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

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<sup>1</sup> Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

<sup>2</sup> For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R3.** Each Generator Owner shall document each known regulatory or equipment limitation<sup>3</sup> that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice.  
*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:
- Identification of a regulatory or equipment limitation.
  - Repair of the equipment causing the limitation that removes the limitation.
  - Replacement of the equipment causing the limitation with equipment that removes the limitation.
  - Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.  
*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

### **C. Measures**

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement

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<sup>3</sup> Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer’s advice.

- M4.** Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

**1.2. Data Retention**

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None



2. Violation Severity Levels

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
| <b>R1</b> | N/A   | N/A   | N/A   | The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.   |
| <b>R2</b> | N/A   | N/A   | N/A   | The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3. |
| <b>R3</b> | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.  |

## Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
|           | limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.   | OR<br>The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.  |
| <b>R4</b> | The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request. | The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner failed to provide trip settings within 150 calendar days of a written request. |

### E. Regional Variances

None

### F. Associated Documents

None

### Version History

| Version | Date        | Action                                | Change Tracking |
|---------|-------------|---------------------------------------|-----------------|
| 1       | May 9, 2013 | Adopted by the NERC Board of Trustees |                 |

## Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

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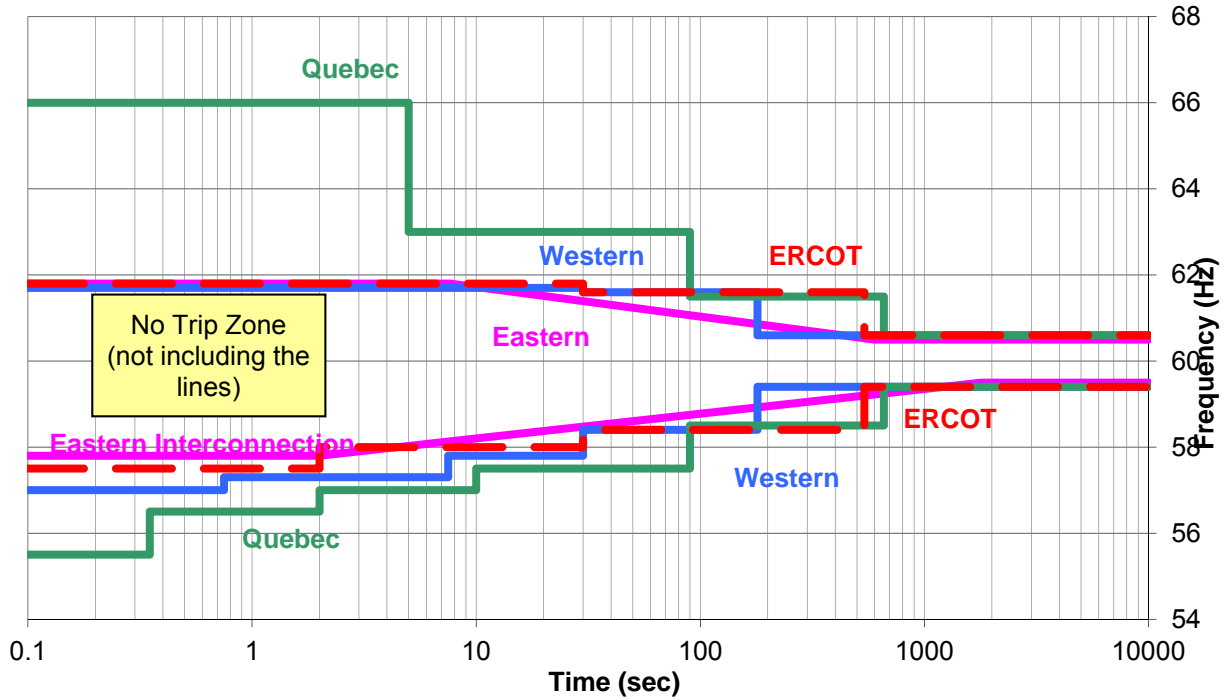
|      |                |   |  |
|------|----------------|---|--|
| 1    | March 20, 2014 | FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.) |  |
| 1(X) | TBD            | Adopted by the NERC Board of Trustees                                       | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

| High Frequency Duration |                           | Low Frequency Duration |                           |
|-------------------------|---------------------------|------------------------|---------------------------|
| Frequency (Hz)          | Time (Sec)                | Frequency (Hz)         | Time (sec)                |
| ≥61.8                   | Instantaneous trip        | ≤57.8                  | Instantaneous trip        |
| ≥60.5                   | $10^{(90.935-1.45713*f)}$ | ≤59.5                  | $10^{(1.7373*f-100.116)}$ |
| <60.5                   | Continuous operation      | > 59.5                 | Continuous operation      |

**Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings**

**Western Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.7                   | Instantaneous trip   | ≤57.0                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤57.3                  | 0.75                 |
| ≥60.6                   | 180                  | ≤57.8                  | 7.5                  |
| <60.6                   | Continuous operation | ≤58.4                  | 30                   |
|                         |                      | ≤59.4                  | 180                  |
|                         |                      | >59.4                  | Continuous operation |

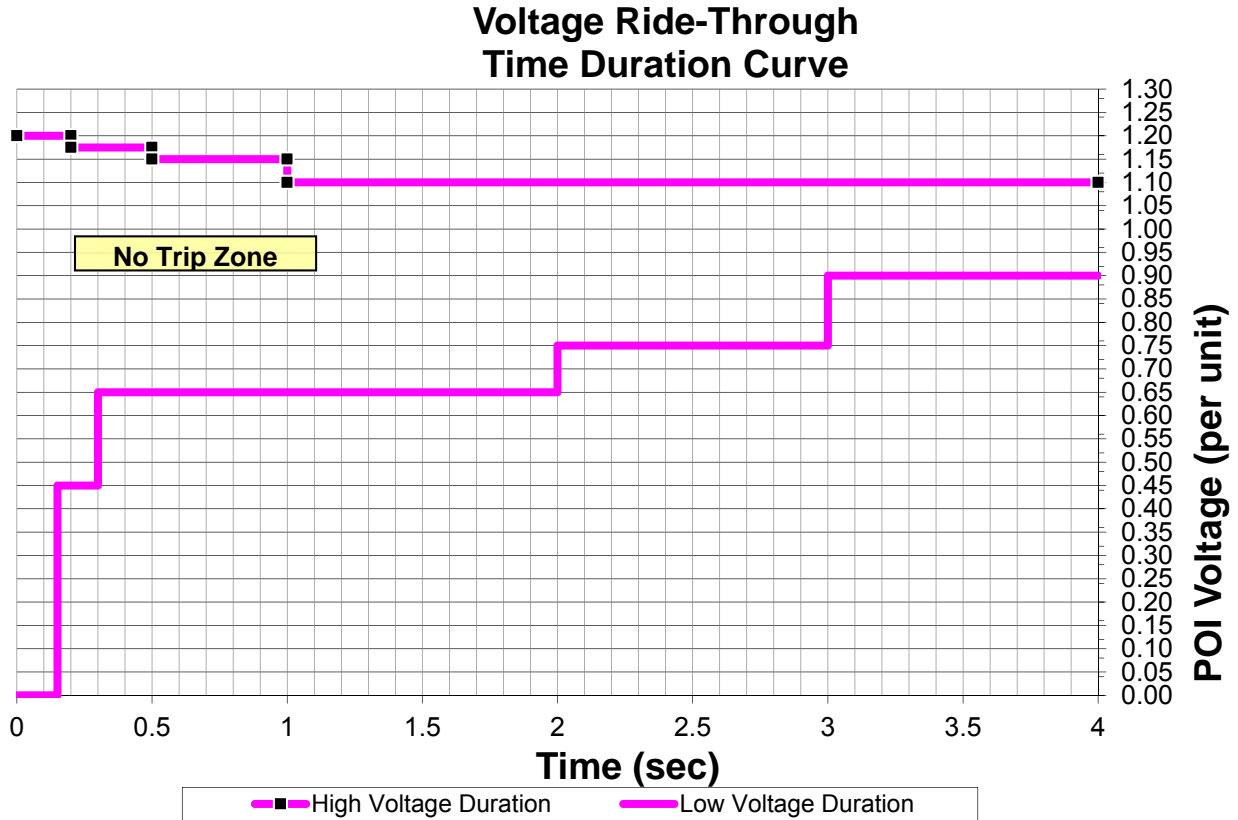
**Quebec Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (Sec)           |
| >66.0                   | Instantaneous trip   | <55.5                  | Instantaneous trip   |
| ≥63.0                   | 5                    | ≤56.5                  | 0.35                 |
| ≥61.5                   | 90                   | ≤57.0                  | 2                    |
| ≥60.6                   | 660                  | ≤57.5                  | 10                   |
| <60.6                   | Continuous operation | ≤58.5                  | 90                   |
|                         |                      | ≤59.4                  | 660                  |
|                         |                      | >59.4                  | Continuous operation |

**ERCOT Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.8                   | Instantaneous trip   | ≤57.5                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤58.0                  | 2                    |
| ≥60.6                   | 540                  | ≤58.4                  | 30                   |
| <60.6                   | Continuous operation | ≤59.4                  | 540                  |
|                         |                      | >59.4                  | Continuous operation |

PRC-024— Attachment 2



**Ride Through Duration:**

| High Voltage Ride Through Duration |                    | Low Voltage Ride Through Duration |            |
|------------------------------------|--------------------|-----------------------------------|------------|
| Voltage (pu)                       | Time (sec)         | Voltage (pu)                      | Time (sec) |
| ≥1.200                             | Instantaneous trip | <0.45                             | 0.15       |
| ≥1.175                             | 0.20               | <0.65                             | 0.30       |
| ≥1.15                              | 0.50               | <0.75                             | 2.00       |
| ≥1.10                              | 1.00               | <0.90                             | 3.00       |

## **Voltage Ride-Through Curve Clarifications**

### **Curve Details:**

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

### **Evaluating Protective Relay Settings:**

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
  - a. All of the units connected to the same transformer are online and operating.
  - b. All of the units are at full nameplate real-power output.
  - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
  - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

**A. Introduction**

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-1(X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
  - 4.1. Generator Owner
5. **Effective Date:**
  - 5.1. In those jurisdictions where regulatory approval is required:
    - 5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
  - 5.2. In those jurisdictions where regulatory approval is not required:
    - 5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
    - 5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.



- 5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
- 5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

## B. Requirements

- R1.** Each Generator Owner that has generator frequency protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
  - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
  - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection<sup>2</sup>) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip in accordance with a ~~Special Protection System (SPS) or Remedial Action Scheme (RAS)~~.
  - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
  - Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

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<sup>1</sup> Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

<sup>2</sup> For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R3.** Each Generator Owner shall document each known regulatory or equipment limitation<sup>3</sup> that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice.  
*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:
- Identification of a regulatory or equipment limitation.
  - Repair of the equipment causing the limitation that removes the limitation.
  - Replacement of the equipment causing the limitation with equipment that removes the limitation.
  - Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.  
*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

### **C. Measures**

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement

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<sup>3</sup> Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer’s advice.

- M4.** Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

**1.2. Data Retention**

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None

2. Violation Severity Levels

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
| <b>R1</b> | N/A   | N/A   | N/A   | The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.   |
| <b>R2</b> | N/A   | N/A   | N/A   | The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3. |
| <b>R3</b> | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.  |

## Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
|           | limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.   | OR<br>The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.  |
| <b>R4</b> | The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request. | The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner failed to provide trip settings within 150 calendar days of a written request. |

### E. Regional Variances

None

### F. Associated Documents

None

### Version History

| Version | Date        | Action                                | Change Tracking |
|---------|-------------|---------------------------------------|-----------------|
| 1       | May 9, 2013 | Adopted by the NERC Board of Trustees |                 |

## Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

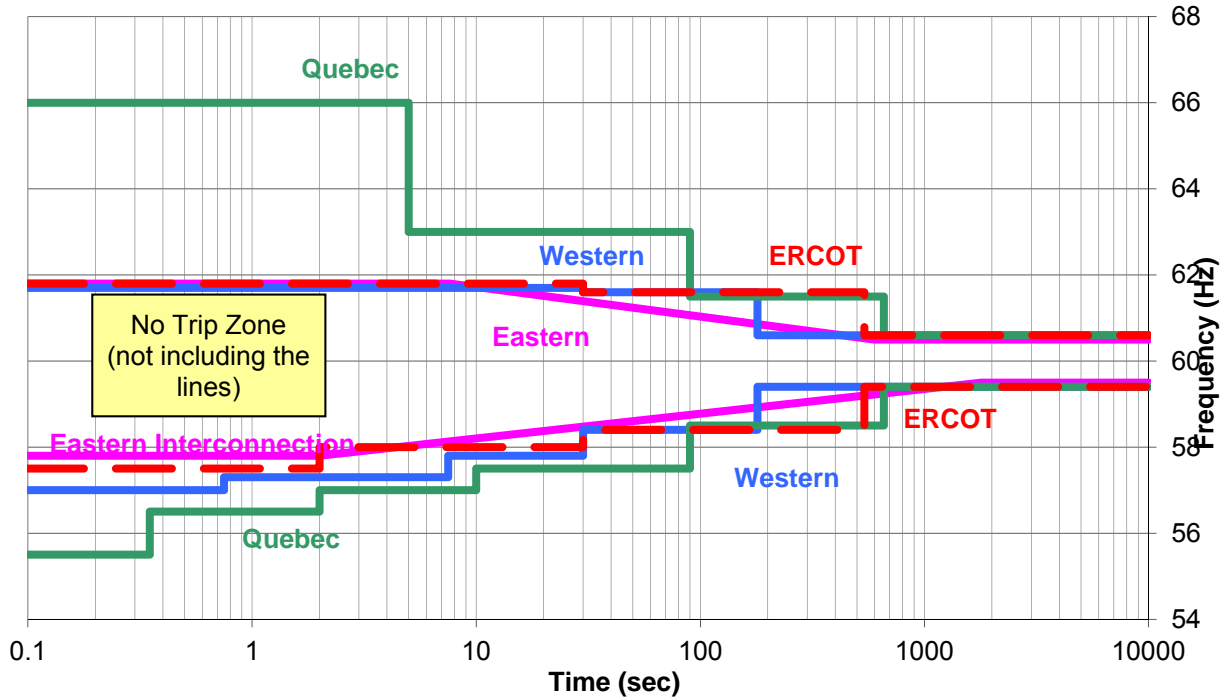
|             |                |   |   |
|-------------|----------------|---|---|
| 1           | March 20, 2014 | FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.) |   |
| <u>1(X)</u> | <u>TBD</u>     | <u>Adopted by the NERC Board of Trustees</u>                                | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

### G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

| High Frequency Duration |                           | Low Frequency Duration |                           |
|-------------------------|---------------------------|------------------------|---------------------------|
| Frequency (Hz)          | Time (Sec)                | Frequency (Hz)         | Time (sec)                |
| ≥61.8                   | Instantaneous trip        | ≤57.8                  | Instantaneous trip        |
| ≥60.5                   | $10^{(90.935-1.45713*f)}$ | ≤59.5                  | $10^{(1.7373*f-100.116)}$ |
| <60.5                   | Continuous operation      | > 59.5                 | Continuous operation      |



**Western Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.7                   | Instantaneous trip   | ≤57.0                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤57.3                  | 0.75                 |
| ≥60.6                   | 180                  | ≤57.8                  | 7.5                  |
| <60.6                   | Continuous operation | ≤58.4                  | 30                   |
|                         |                      | ≤59.4                  | 180                  |
|                         |                      | >59.4                  | Continuous operation |

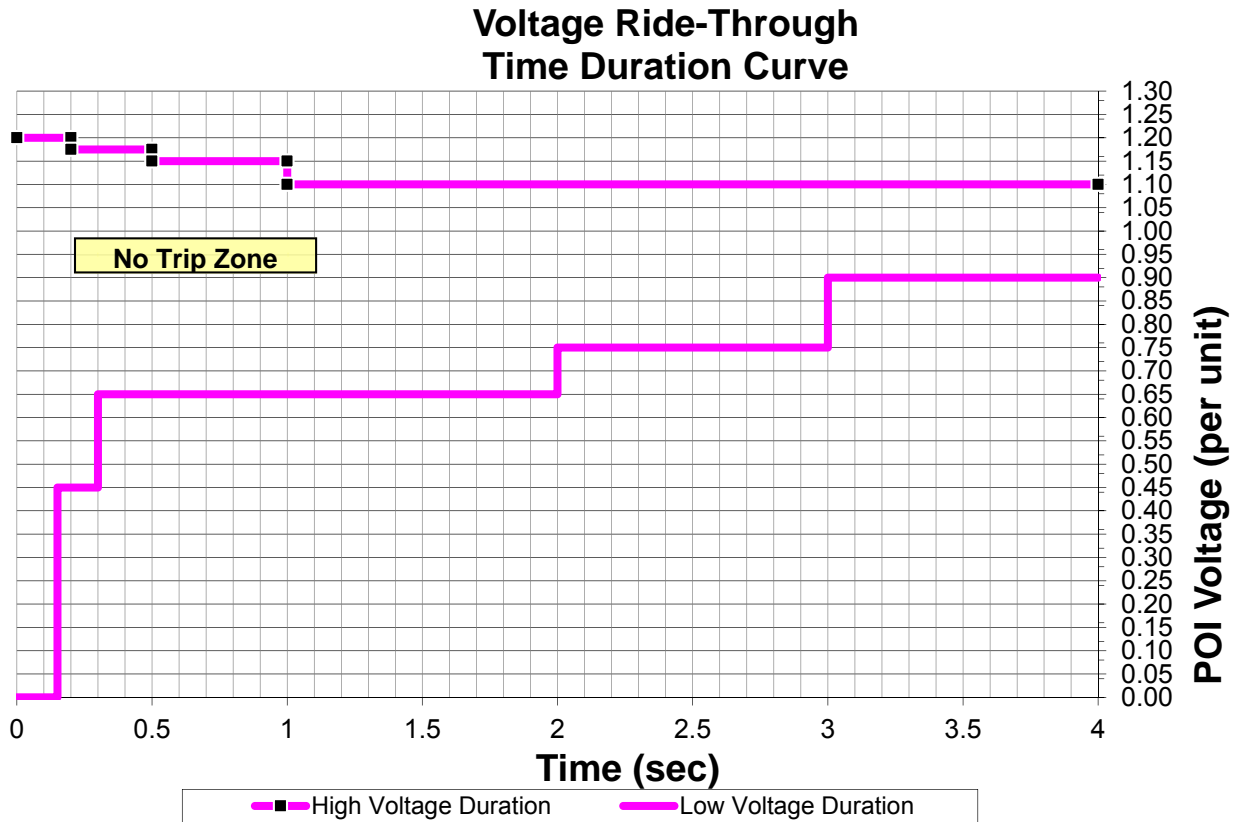
**Quebec Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (Sec)           |
| >66.0                   | Instantaneous trip   | <55.5                  | Instantaneous trip   |
| ≥63.0                   | 5                    | ≤56.5                  | 0.35                 |
| ≥61.5                   | 90                   | ≤57.0                  | 2                    |
| ≥60.6                   | 660                  | ≤57.5                  | 10                   |
| <60.6                   | Continuous operation | ≤58.5                  | 90                   |
|                         |                      | ≤59.4                  | 660                  |
|                         |                      | >59.4                  | Continuous operation |

**ERCOT Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.8                   | Instantaneous trip   | ≤57.5                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤58.0                  | 2                    |
| ≥60.6                   | 540                  | ≤58.4                  | 30                   |
| <60.6                   | Continuous operation | ≤59.4                  | 540                  |
|                         |                      | >59.4                  | Continuous operation |

PRC-024— Attachment 2



**Ride Through Duration:**

| High Voltage Ride Through Duration |                    | Low Voltage Ride Through Duration |            |
|------------------------------------|--------------------|-----------------------------------|------------|
| Voltage (pu)                       | Time (sec)         | Voltage (pu)                      | Time (sec) |
| ≥1.200                             | Instantaneous trip | <0.45                             | 0.15       |
| ≥1.175                             | 0.20               | <0.65                             | 0.30       |
| ≥1.15                              | 0.50               | <0.75                             | 2.00       |
| ≥1.10                              | 1.00               | <0.90                             | 3.00       |

## Voltage Ride-Through Curve Clarifications

### Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

### Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
  - a. All of the units connected to the same transformer are online and operating.
  - b. All of the units are at full nameplate real-power output.
  - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
  - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

## A. Introduction

1. **Title:** Generator Relay Loadability

2. **Number:** PRC-025-1(X)

**Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

### 3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.2. **Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.<sup>1</sup>

3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

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<sup>1</sup> These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1(X) Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.<sup>2</sup>

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

## B. Requirements and Measures

- R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.  
*[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
- M1.** For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1(X) – Attachment 1: Relay Settings.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

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<sup>2</sup> Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon       | VRF  | Violation Severity Levels |              |          |   |
|-----|--------------------|------|---------------------------|--------------|----------|---|
|     |                    |      | Lower VSL                 | Moderate VSL | High VSL | Severe VSL  |
| R1  | Long-Term Planning | High | N/A                       | N/A          | N/A      | The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on an applied load-responsive protective relay. |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

## **PRC-025-1(X) – Attachment 1: Relay Settings**

### **Introduction**

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

### **Generators**

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

### **Transformers**

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.



## Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

## Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.<sup>3</sup>
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

## Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

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<sup>3</sup> IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

| Table 1. Relay Loadability Evaluation Criteria   |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system | 1a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b>                             |  |           |   |   |  |

<sup>4</sup> Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

| Table 1. Relay Loadability Evaluation Criteria   |   |   |  |  |  |
|--|---|---|--|--|--|
| Application  | Relay Type  | Option  | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 2a  | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b>   |  |  |  |
|  |   | 2b  | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b>   |  |  |  |
|  | 2c  | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and<br>(2) Reactive Power output – 100% of the maximum gross Mvar output during field-forcing as determined by simulation |  |  |
| <b>The same application continues with a different relay type below</b>  |   |   |  |  |  |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 3   | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |  |
| <b>A different application starts on the next page</b>   |   |   |  |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |   |        |   |  |
|--|---|--------|---|--|
| Application  | Relay Type  | Option | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |
| Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system                                  | 4      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|  | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 5      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 6      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |
| A different application starts on the next page  |   |        |   |  |

| Table 1. Relay Loadability Evaluation Criteria                                     |  |           |   |  |  |
|--|--|-----------|---|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 14 | 7a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b> |  |           |   |  |  |

| Table 1. Relay Loadability Evaluation Criteria                                     |   |           |   |   |  |
|--|---|-----------|---|---|--|
| Application  | Relay Type  | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 15 | 8a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b> |   |           |   |   |  |

| Table 1. Relay Loadability Evaluation Criteria                       |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 16 | 9a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>A different application starts on the next page</b>               |  |           |   |   |  |



| Table 1. Relay Loadability Evaluation Criteria  |  |        |  |  |
|---|--|--------|--|--|
| Application   | Relay Type   | Option | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 17 | 10     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|   | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 18                                      | 11     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | <b>The same application continues on the next page with a different relay type</b>   |        |  |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |   |  |  |
|---|--|-----------|---|--|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer                | 12        | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |  |
|   | If the relay is installed on the high-side of the GSU transformer use Option 19  |           |   |  |  |
| <b>A different application starts below</b>   |  |           |   |  |  |
| Unit auxiliary transformer(s) (UAT)   | Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip. | 13a       | 1.0 per unit of the winding nominal voltage of the unit auxiliary transformer   | The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating  |  |
|   |  | <b>OR</b> |   |  |  |
|   |  | 13b       | Unit auxiliary transformer bus voltage corresponding to the measured current  | The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner  |  |
| <b>A different application starts on the next page</b>  |  |           |   |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |  |           |  |  |
|--|--|-----------|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators | Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer | 14a       | 0.85 per unit of the line nominal voltage  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |
|  |  | <b>OR</b> |  |  |
|  | If the relay is installed on the generator-side of the GSU transformer use Option 7  | 14b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |
| <b>The same application continues on the next page with a different relay type</b>   |  |           |  |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |   |  |  |
|---|--|-----------|---|--|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators</p> | <p>Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 8</p> | 15a       | 0.85 per unit of the line nominal voltage   | <p>The overcurrent element shall be set greater than 115% of the calculated current derived from:</p> <p>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and</p> <p>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</p> |  |
|   |  | <b>OR</b> |   |  |  |
|   |  | 15b       | <p>Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</p> | <p>The overcurrent element shall be set greater than 115% of the calculated current derived from:</p> <p>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and</p> <p>(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</p>      |  |
| <b>The same application continues on the next page with a different relay type</b>  |  |           |   |  |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |  |   |  |
|---|--|-----------|--|---|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria   |  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators | Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer | 16a       | 0.85 per unit of the line nominal voltage  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|   |  | <b>OR</b> |  |   |  |
|   |  | 16b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| A different application starts on the next page   |  |           |  |   |  |

| Table 1. Relay Loadability Evaluation Criteria  |   |        |  |   |
|---|---|--------|--|---|
| Application   | Relay Type  | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria   |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer | 17     | 1.0 per unit of the line nominal voltage | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | If the relay is installed on the generator-side of the GSU transformer use Option 10                                      |        |  |   |
| <b>The same application continues on the next page with a different relay type</b>  |   |        |  |   |

| Table 1. Relay Loadability Evaluation Criteria   |   |        |  |  |
|--|---|--------|--|--|
| Application  | Relay Type  | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria  |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p> | <p>Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer</p> | 18     | 1.0 per unit of the line nominal voltage | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|  | <p><b>The same application continues on the next page with a different relay type</b></p>   |        |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |  |        |  |  |
|--|--|--------|--|--|
| Application  | Relay Type   | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria  |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p> | <p>Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 12</p> | 19     | 1.0 per unit of the line nominal voltage | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
| End of Table 1   |  |        |  |  |



**Rationale:**

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

**Rationale for R1:**

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

**Version History**

| Version | Date            | Action                                | Change Tracking  |
|---------|-----------------|---------------------------------------|--|
| 1       | August 15, 2013 | Adopted by NERC Board of Trustees     | New  |
| 1(X)    | TBD             | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Generator Relay Loadability

2. **Number:** PRC-025-1(X)

**Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

### 3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.2. **Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.<sup>1</sup>

3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

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<sup>1</sup> These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1(X) Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.<sup>2</sup>

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

## B. Requirements and Measures

- R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.  
*[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
- M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1(X) – Attachment 1: Relay Settings.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Evidence Retention

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

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<sup>2</sup> Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None

**Table of Compliance Elements**

| R # | Time Horizon       | VRF  | Violation Severity Levels |              |          |   |
|-----|--------------------|------|---------------------------|--------------|----------|---|
|     |                    |      | Lower VSL                 | Moderate VSL | High VSL | Severe VSL  |
| R1  | Long-Term Planning | High | N/A                       | N/A          | N/A      | The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with <i>PRC-025-1(X) – Attachment 1: Relay Settings</i> , on an applied load-responsive protective relay. |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

## **PRC-025-1(X) – Attachment 1: Relay Settings**

### **Introduction**

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

### **Generators**

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

### **Transformers**

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

## Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

## Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.<sup>3</sup>
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

## Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

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<sup>3</sup> IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.



| Table 1. Relay Loadability Evaluation Criteria   |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system | 1a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b>                             |  |           |   |   |  |

<sup>4</sup> Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

| Table 1. Relay Loadability Evaluation Criteria   |   |   |  |  |  |
|--|---|---|--|--|--|
| Application  | Relay Type  | Option  | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 2a  | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b>   |  |  |  |
|  |   | 2b  | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b>   |  |  |  |
|  | 2c  | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and<br>(2) Reactive Power output – 100% of the maximum gross Mvar output during field-forcing as determined by simulation |  |  |
| <b>The same application continues with a different relay type below</b>  |   |   |  |  |  |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 3   | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |  |
| <b>A different application starts on the next page</b>   |   |   |  |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |   |        |   |  |
|--|---|--------|---|--|
| Application  | Relay Type  | Option | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |
| Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system                                  | 4      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|  | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 5      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 6      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |
| A different application starts on the next page  |   |        |   |  |

| Table 1. Relay Loadability Evaluation Criteria                                     |  |           |   |  |  |
|--|--|-----------|---|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 14 | 7a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b> |  |           |   |  |  |

| Table 1. Relay Loadability Evaluation Criteria                                     |   |           |   |   |  |
|--|---|-----------|---|---|--|
| Application  | Relay Type  | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 15 | 8a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b> |   |           |   |   |  |

| Table 1. Relay Loadability Evaluation Criteria                       |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 16 | 9a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>A different application starts on the next page</b>               |  |           |   |   |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |        |  |  |
|---|--|--------|--|--|
| Application   | Relay Type   | Option | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 17 | 10     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|   | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 18                                      | 11     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | <b>The same application continues on the next page with a different relay type</b>   |        |  |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |   |  |  |
|---|--|-----------|---|--|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer                | 12        | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |  |
|   | If the relay is installed on the high-side of the GSU transformer use Option 19  |           |   |  |  |
| <b>A different application starts below</b>   |  |           |   |  |  |
| Unit auxiliary transformer(s) (UAT)   | Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip. | 13a       | 1.0 per unit of the winding nominal voltage of the unit auxiliary transformer   | The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating  |  |
|   |  | <b>OR</b> |   |  |  |
|   |  | 13b       | Unit auxiliary transformer bus voltage corresponding to the measured current  | The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner  |  |
| <b>A different application starts on the next page</b>  |  |           |   |  |  |



| Table 1. Relay Loadability Evaluation Criteria   |  |           |  |  |
|--|--|-----------|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators | Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer | 14a       | 0.85 per unit of the line nominal voltage  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |
|  |  | <b>OR</b> |  |  |
|  | If the relay is installed on the generator-side of the GSU transformer use Option 7  | 14b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |
| <b>The same application continues on the next page with a different relay type</b>   |  |           |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |   |           |  |   |  |
|--|---|-----------|--|---|--|
| Application  | Relay Type  | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria   |  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators | Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer<br><br>If the relay is installed on the generator-side of the GSU transformer use Option 8 | 15a       | 0.85 per unit of the line nominal voltage  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |  |   |  |
|  |   | 15b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b>   |   |           |  |   |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |  |   |  |
|---|--|-----------|--|---|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria   |  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators | Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer | 16a       | 0.85 per unit of the line nominal voltage  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|   |  | <b>OR</b> |  |   |  |
|   |  | 16b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| A different application starts on the next page   |  |           |  |   |  |

| Table 1. Relay Loadability Evaluation Criteria  |   |        |  |   |
|---|---|--------|--|---|
| Application   | Relay Type  | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria   |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer | 17     | 1.0 per unit of the line nominal voltage | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | If the relay is installed on the generator-side of the GSU transformer use Option 10                                      |        |  |   |
| <b>The same application continues on the next page with a different relay type</b>  |   |        |  |   |

| Table 1. Relay Loadability Evaluation Criteria   |   |        |  |  |
|--|---|--------|--|--|
| Application  | Relay Type  | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria  |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p> | <p>Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer</p> | 18     | 1.0 per unit of the line nominal voltage | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|  | <p><b>The same application continues on the next page with a different relay type</b></p>   |        |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |  |        |  |  |
|--|--|--------|--|--|
| Application  | Relay Type   | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria  |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p> | <p>Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 12</p> | 19     | 1.0 per unit of the line nominal voltage | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
| End of Table 1   |  |        |  |  |

**Rationale:**

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

**Rationale for R1:**

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

**Version History**

| <b>Version</b> | <b>Date</b>     | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|-----------------|---------------------------------------|--|
| 1              | August 15, 2013 | Adopted by NERC Board of Trustees     | New  |
| 1(X)           | TBD             | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-2a(X)
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Purchasing Selling Entities.
5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

## B. Requirements

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

## C. Measures

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.



**1.2. Compliance Monitoring Period and Reset Time Frame**

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

**1.3. Data Retention**

Not specified.

**1.4. Additional Compliance Information**

Not specified.

2. Violation Severity Levels:

| R# | Lower  | Moderate | High | Severe   |
|----|--|----------|------|--|
| R1 | N/A  | N/A      | N/A  | The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.             |
| R2 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |
| R3 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |

**E. Regional Variances**

None identified.

**Version History**

| Version | Date             | Action  | Change Tracking  |
|---------|------------------|---|--|
| 0       | April 1, 2005    | Effective Date  | New  |
| 0       | August 8, 2005   | Removed “Proposed” from Effective Date  | Errata   |
| 1       |                  | Removed the Reliability Coordinator from the list of responsible functional entities<br>Deleted R1 and R1.1<br>Modified M1 to omit the reference to the Reliability Coordinator<br>Deleted VSLs for R1 and R1.1 | Revised  |
| 2       | October 17, 2008 | Adopted by NERC Board of Trustees   | New  |
| 2       | March 17, 2011   | Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)   |  |
| 2a      | April 21, 2011   | Added FERC approved Interpretation  |  |
| 2a(X)   | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Attachment 1-TOP-005**

**Electric System Reliability Data**

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

- 1.** The following information shall be updated at least every ten minutes:
  - 1.1.** Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
    - 1.1.1** Status.
    - 1.1.2** MW or ampere loadings.
    - 1.1.3** MVA capability.
    - 1.1.4** Transformer tap and phase angle settings.
    - 1.1.5** Key voltages.
  - 1.2.** Generator data.
    - 1.2.1** Status.
    - 1.2.2** MW and MVAR capability.
    - 1.2.3** MW and MVAR net output.
    - 1.2.4** Status of automatic voltage control facilities.
  - 1.3.** Operating reserve.
    - 1.3.1** MW reserve available within ten minutes.
  - 1.4.** Balancing Authority demand.
    - 1.4.1** Instantaneous.
  - 1.5.** Interchange.
    - 1.5.1** Instantaneous actual interchange with each Balancing Authority.
    - 1.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
    - 1.5.3** Interchange Schedules for the next 24 hours.
  - 1.6.** Area Control Error and frequency.
    - 1.6.1** Instantaneous area control error.
    - 1.6.2** Clock hour area control error.
    - 1.6.3** System frequency at one or more locations in the Balancing Authority.
- 2.** Other operating information updated as soon as available.
  - 2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
  - 2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
  - 2.3.** Forecast peak demand for current day and next day.
  - 2.4.** Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded Remedial Action Schemes.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Appendix 2

| Requirement Number and Text of Requirement  |
|---|
| <p><b>TOP-005-1 Requirement R3<sup>1</sup></b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12</b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation   |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>  |

<sup>1</sup> In the current version of the Standard (TOP-005-2a), this requirement is R2.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

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## B. Requirements

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

## C. Measures

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.



**1.2. Compliance Monitoring Period and Reset Time Frame**

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

**1.3. Data Retention**

Not specified.

**1.4. Additional Compliance Information**

Not specified.

2. Violation Severity Levels:

| R# | Lower  | Moderate | High | Severe   |
|----|--|----------|------|--|
| R1 | N/A  | N/A      | N/A  | The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.             |
| R2 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |
| R3 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |

**E. Regional Variances**

None identified.

**Version History**

| Version      | Date             | Action  | Change Tracking   |
|--------------|------------------|---|---|
| 0            | April 1, 2005    | Effective Date  | New   |
| 0            | August 8, 2005   | Removed “Proposed” from Effective Date  | Errata  |
| 1            |                  | Removed the Reliability Coordinator from the list of responsible functional entities<br>Deleted R1 and R1.1<br>Modified M1 to omit the reference to the Reliability Coordinator<br>Deleted VSLs for R1 and R1.1 | Revised   |
| 2            | October 17, 2008 | Adopted by NERC Board of Trustees   | New   |
| 2            | March 17, 2011   | Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)   |   |
| 2a           | April 21, 2011   | Added FERC approved Interpretation  |   |
| <u>2a(X)</u> | <u>TBD</u>       | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**Attachment 1-TOP-005**

**Electric System Reliability Data**

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

- 1.** The following information shall be updated at least every ten minutes:
  - 1.1.** Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
    - 1.1.1** Status.
    - 1.1.2** MW or ampere loadings.
    - 1.1.3** MVA capability.
    - 1.1.4** Transformer tap and phase angle settings.
    - 1.1.5** Key voltages.
  - 1.2.** Generator data.
    - 1.2.1** Status.
    - 1.2.2** MW and MVAR capability.
    - 1.2.3** MW and MVAR net output.
    - 1.2.4** Status of automatic voltage control facilities.
  - 1.3.** Operating reserve.
    - 1.3.1** MW reserve available within ten minutes.
  - 1.4.** Balancing Authority demand.
    - 1.4.1** Instantaneous.
  - 1.5.** Interchange.
    - 1.5.1** Instantaneous actual interchange with each Balancing Authority.
    - 1.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
    - 1.5.3** Interchange Schedules for the next 24 hours.
  - 1.6.** Area Control Error and frequency.
    - 1.6.1** Instantaneous area control error.
    - 1.6.2** Clock hour area control error.
    - 1.6.3** System frequency at one or more locations in the Balancing Authority.
- 2.** Other operating information updated as soon as available.
  - 2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
  - 2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
  - 2.3.** Forecast peak demand for current day and next day.
  - 2.4.** Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded ~~special protection systems~~ Remedial Action Schemes.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3<sup>1</sup></b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or degraded <u>special protection system Remedial Action Schemes</u>. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12</b></p> <p><b>R12.</b> Whenever a <u>Special Protection System Remedial Action Scheme</u> that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that <u>Special Protection System Remedial Action Scheme</u> on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the <u>Special Protection System Remedial Action Scheme</u> including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a <u>SPS RAS</u> shall have a documented Regional Reliability Organization <u>SPS RAS</u> review procedure to ensure that <u>SPS RAS</u>s comply with Regional criteria and NERC Reliability Standards. The Regional <u>SPS RAS</u> review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the <u>SPS RAS</u> shall be designed so that a single <u>SPSRAS</u> component failure, when the <u>SPSRAS</u> was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation  |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires</p>  |

<sup>1</sup> In the current version of the Standard (TOP-005-2a), this requirement is R2.

data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for [SPSRAS](#) information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a [SPSRAS](#) to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the [SPSRAS](#) to operate as designed, then such a condition can be, but is not mandated to be, reported.

### Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a [SPSRAS](#) to operate as designed. If the loss of a communication channel will result in the failure of a [SPSRAS](#) to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the [SPSRAS](#) to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** May 13, 2009

## B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
    - R1.3.5. Have all projected firm transfers modeled.



- R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(X)\_R1 and TPL-001-0.1(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(X)\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|------------------|---|--|
| 0              | April 1, 2005    | Effective Date  | New  |
| 0              | February 8, 2005 | BOT Approval  | Revised  |
| 0              | June 3, 2005     | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata   |
| 0              | July 24, 2007    | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata   |
| 0.1            | October 29, 2008 | BOT adopted errata changes; updated version number to "0.1"       | Errata   |
| 0.1            | May 13, 2009     | FERC Approved – Updated Effective Date                            | Revised  |
| 0.1(X)         | TBD              | Adopted by the NERC Board of Trustees                             | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                      |
|--|--|---|--|----------------------|
|  |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers   | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>   | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>e</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | Bipolar Block, with Normal Clearing <sup>e</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>e</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>   | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |

**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

|   |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
|---|---|--------------|----------------|-------------------------|----------------|--|--|--|---|--|---|---|--|---|---|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>  | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <table border="0"> <tr> <td>5. Breaker (failure or internal Fault)</td> </tr> <tr> <td>6. Loss of towerline with three or more circuits</td> </tr> <tr> <td>7. All transmission lines on a common right-of way</td> </tr> <tr> <td>8. Loss of a substation (one voltage level plus transformers)</td> </tr> <tr> <td>9. Loss of a switching station (one voltage level plus transformers)</td> </tr> <tr> <td>10. Loss of all generating units at a station</td> </tr> <tr> <td>11. Loss of a large Load or major Load center</td> </tr> <tr> <td>12. Failure of a fully redundant Remedial Action Scheme to operate when required</td> </tr> <tr> <td>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</td> </tr> <tr> <td>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</td> </tr> </table> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | 5. Breaker (failure or internal Fault) | 6. Loss of towerline with three or more circuits | 7. All transmission lines on a common right-of way | 8. Loss of a substation (one voltage level plus transformers) | 9. Loss of a switching station (one voltage level plus transformers) | 10. Loss of all generating units at a station | 11. Loss of a large Load or major Load center | 12. Failure of a fully redundant Remedial Action Scheme to operate when required | 13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate | 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer  |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 2. Transmission Circuit   | 4. Bus Section  |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 5. Breaker (failure or internal Fault)  |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 6. Loss of towerline with three or more circuits  |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 7. All transmission lines on a common right-of way  |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 8. Loss of a substation (one voltage level plus transformers)   |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 9. Loss of a switching station (one voltage level plus transformers)  |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 10. Loss of all generating units at a station   |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 11. Loss of a large Load or major Load center   |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 12. Failure of a fully redundant Remedial Action Scheme to operate when required  |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |
| 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.   |   |              |                |                         |                |  |  |  |   |  |   |   |  |   |   |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** May 13, 2009

## B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
    - R1.3.5. Have all projected firm transfers modeled.

- R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
- R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(X)\_R1 and TPL-001-0.1(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(X)\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version           | Date             | Action  | Change Tracking   |
|-------------------|------------------|---|---|
| 0                 | April 1, 2005    | Effective Date  | New   |
| 0                 | February 8, 2005 | BOT Approval  | Revised   |
| 0                 | June 3, 2005     | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata  |
| 0                 | July 24, 2007    | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata  |
| 0.1               | October 29, 2008 | BOT adopted errata changes; updated version number to "0.1"       | Errata  |
| 0.1               | May 13, 2009     | FERC Approved – Updated Effective Date                            | Revised   |
| <del>0.1(X)</del> | <del>TBD</del>   | <del>Adopted by the NERC Board of Trustees</del>                  | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |

**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                      |
|--|--|---|--|----------------------|
|  |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers   | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>   | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>e</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | Bipolar Block, with Normal Clearing <sup>e</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>e</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>   | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |



**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

|  |   |   |
|--|---|---|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant <del>Special Protection System Remedial Action Scheme (or remedial action scheme)</del> to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System Remedial Action Scheme (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the <del>interconnected systems may or may not achieve a new, stable operating point.</del></li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|--|---|---|

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## A. Introduction

1. **Title:** Transmission System Planning Performance Requirements
2. **Number:** TPL-001-4(X)
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**
  - 4.1. **Functional Entity**
    - 4.1.1. Planning Coordinator.
    - 4.1.2. Transmission Planner.
5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4(X), Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4(X):

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

## B. Requirements

- R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 1.1.** System models shall represent:
- 1.1.1.** Existing Facilities
  - 1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
  - 1.1.3.** New planned Facilities and changes to existing Facilities
  - 1.1.4.** Real and reactive Load forecasts
  - 1.1.5.** Known commitments for Firm Transmission Service and Interchange
  - 1.1.6.** Resources (supply or demand side) required for Load
- R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 2.1.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:
- 2.1.1.** System peak Load for either Year One or year two, and for year five.
  - 2.1.2.** System Off-Peak Load for one of the five years.
  - 2.1.3.** P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.
  - 2.1.4.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :
    - Real and reactive forecasted Load.
    - Expected transfers.
    - Expected in service dates of new or modified Transmission Facilities.
    - Reactive resource capability.
    - Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
  - Duration or timing of known Transmission outages.
- 2.1.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
- 2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
- 2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.
- 2.3.** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
- 2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:
- 2.4.1.** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
- 2.4.2.** System Off-Peak Load for one of the five years.
- 2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
- Load level, Load forecast, or dynamic Load model assumptions.
  - Expected transfers.
  - Expected in service dates of new or modified Transmission Facilities.
  - Reactive resource capability.
  - Generation additions, retirements, or other dispatch scenarios.

- 2.5.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.
- 2.6.** Past studies may be used to support the Planning Assessment if they meet the following requirements:
- 2.6.1.** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- 2.6.2.** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.
- 2.7.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
- 2.7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
  - Installation, modification, or removal of Protection Systems or Remedial Action Schemes
  - Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
  - Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
  - Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
  - Use of rate applications, DSM, new technologies, or other initiatives.
- 2.7.2.** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.
- 2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

**2.7.4.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

**2.8.** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

**2.8.1.** List System deficiencies and the associated actions needed to achieve required System performance.

**2.8.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

**R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**3.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

**3.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

**3.3.** Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

**3.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

**3.3.1.1.** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

**3.3.1.2.** Tripping of Transmission elements where relay loadability limits are exceeded.

**3.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

**3.4.** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies

to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

- 3.4.1.** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
      - 3.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.
    - R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
      - 4.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.
        - 4.1.1.** For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.
        - 4.1.2.** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.
        - 4.1.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.
      - 4.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.
      - 4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :
        - 4.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
          - 4.3.1.1.** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
          - 4.3.1.2.** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

- 4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
    - 4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.
  - 4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
    - 4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
  - 4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.
- R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*
- R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
  - 8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.



Table 1 – Steady State & Stability Performance Planning Events

**Steady State & Stability:**

- a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
- b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
- c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
- d. Simulate Normal Clearing unless otherwise specified.
- e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

**Steady State Only:**

- f. Applicable Facility Ratings shall not be exceeded.
- g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
- h. Planning event P0 is applicable to steady state only.
- i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

**Stability Only:**

- j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

| Category   | Initial Condition | Event <sup>1</sup>  | Fault Type <sup>2</sup> | BES Level <sup>3</sup> | Interruption of Firm Transmission Service Allowed <sup>4</sup> | Non-Consequential Load Loss Allowed |
|--|-------------------|---|-------------------------|------------------------|--|-------------------------------------|
| <b>P0</b><br>No Contingency                              | Normal System     | None  | N/A                     | EHV, HV                | No   | No                                  |
| <b>P1</b><br>Single Contingency                          | Normal System     | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup> | 3Ø                      | EHV, HV                | No <sup>9</sup>  | No <sup>12</sup>                    |
|  |                   | 5. Single Pole of a DC line   | SLG                     |                        |  |                                     |
| <b>P2</b><br>Single Contingency                          | Normal System     | 1. Opening of a line section w/o a fault <sup>7</sup>   | N/A                     | EHV, HV                | No <sup>9</sup>  | No <sup>12</sup>                    |
|  |                   | 2. Bus Section Fault  | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
|  |                   |   |                         | HV                     | Yes  | Yes                                 |
|  |                   | 3. Internal Breaker Fault <sup>8</sup><br>(non-Bus-tie Breaker)   | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
| HV   | Yes               |   |                         | Yes                    |  |                                     |
| 4. Internal Breaker Fault (Bus-tie Breaker) <sup>8</sup> | SLG               | EHV, HV   | Yes                     | Yes                    |  |                                     |

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| Category  | Initial Condition  | Event <sup>1</sup>  | Fault Type <sup>2</sup> | BES Level <sup>3</sup> | Interruption of Firm Transmission Service Allowed <sup>4</sup> | Non-Consequential Load Loss Allowed |
|---|--|---|-------------------------|------------------------|--|-------------------------------------|
| <b>P3</b><br>Multiple Contingency   | Loss of generator unit followed by System adjustments <sup>9</sup>   | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup>   | 3Ø                      | EHV, HV                | No <sup>9</sup>  | No <sup>12</sup>                    |
|   |  | 5. Single pole of a DC line   | SLG                     |                        |  |                                     |
| <b>P4</b><br>Multiple Contingency<br><i>(Fault plus stuck breaker<sup>10</sup>)</i> | Normal System  | Loss of multiple elements caused by a stuck breaker <sup>10</sup> (non-Bus-tie Breaker) attempting to clear a Fault on one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup><br>5. Bus Section                      | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
|   |  | 6. Loss of multiple elements caused by a stuck breaker <sup>10</sup> (Bus-tie Breaker) attempting to clear a Fault on the associated bus  |                         | HV                     | Yes  | Yes                                 |
|   |  |   |                         | SLG                    | EHV, HV  | Yes                                 |
| <b>P5</b><br>Multiple Contingency<br><i>(Fault plus relay failure to operate)</i>   | Normal System  | Delayed Fault Clearing due to the failure of a non-redundant relay <sup>13</sup> protecting the Faulted element to operate as designed, for one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup><br>5. Bus Section | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
|   |  |   |                         | HV                     | Yes  | Yes                                 |
| <b>P6</b><br>Multiple Contingency<br><i>(Two overlapping singles)</i>               | Loss of one of the following followed by System adjustments. <sup>9</sup><br>1. Transmission Circuit<br>2. Transformer <sup>5</sup><br>3. Shunt Device <sup>6</sup><br>4. Single pole of a DC line | Loss of one of the following:<br>1. Transmission Circuit<br>2. Transformer <sup>5</sup><br>3. Shunt Device <sup>6</sup>   | 3Ø                      | EHV, HV                | Yes  | Yes                                 |
|   |  | 4. Single pole of a DC line   | SLG                     |                        |  |                                     |

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| Category   | Initial Condition | Event <sup>1</sup>  | Fault Type <sup>2</sup> | BES Level <sup>3</sup> | Interruption of Firm Transmission Service Allowed <sup>4</sup> | Non-Consequential Load Loss Allowed |
|--|-------------------|---|-------------------------|------------------------|--|-------------------------------------|
| <b>P7</b><br>Multiple Contingency<br><i>(Common Structure)</i> | Normal System     | The loss of:<br>1. Any two adjacent (vertically or horizontally) circuits on common structure <sup>11</sup><br>2. Loss of a bipolar DC line | SLG                     | EHV, HV                | Yes  | Yes                                 |

**Table 1 – Steady State & Stability Performance Extreme Events**

| Table 1 – Steady State & Stability Performance Extreme Events  |   |
|--|---|
| <p><b>Steady State &amp; Stability</b></p> <p>For all extreme events evaluated:</p> <ol style="list-style-type: none"> <li>a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.</li> <li>b. Simulate Normal Clearing unless otherwise specified.</li> </ol>   |   |
| <p><b>Steady State</b></p> <ol style="list-style-type: none"> <li>1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.</li> <li>2. Local area events affecting the Transmission System such as:                     <ol style="list-style-type: none"> <li>a. Loss of a tower line with three or more circuits.<sup>11</sup></li> <li>b. Loss of all Transmission lines on a common Right-of-Way<sup>11</sup>.</li> <li>c. Loss of a switching station or substation (loss of one voltage level plus transformers).</li> <li>d. Loss of all generating units at a generating station.</li> <li>e. Loss of a large Load or major Load center.</li> </ol> </li> <li>3. Wide area events affecting the Transmission System based on System topology such as:                     <ol style="list-style-type: none"> <li>a. Loss of two generating stations resulting from conditions such as:                             <ol style="list-style-type: none"> <li>i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.</li> <li>ii. Loss of the use of a large body of water as the cooling source for generation.</li> <li>iii. Wildfires.</li> <li>iv. Severe weather, e.g., hurricanes, tornadoes, etc.</li> <li>v. A successful cyber attack.</li> <li>vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.</li> </ol> </li> <li>b. Other events based upon operating experience that may result in wide area disturbances.</li> </ol> </li> </ol> | <p><b>Stability</b></p> <ol style="list-style-type: none"> <li>1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.</li> <li>2. Local or wide area events affecting the Transmission System such as:                     <ol style="list-style-type: none"> <li>a. 3Ø fault on generator with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>b. 3Ø fault on Transmission circuit with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>c. 3Ø fault on transformer with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>d. 3Ø fault on bus section with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>e. 3Ø internal breaker fault.</li> <li>f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</li> </ol> </li> </ol> |

**Table 1 – Steady State & Stability Performance Footnotes  
(Planning Events and Extreme Events)**

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3 $\emptyset$ ) are the fault types that must be evaluated in Stability simulations for the event described. A 3 $\emptyset$  or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
  - a. Date, time, and location for the meeting
  - b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
  - c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
  - a. System Load level and estimated annual hours of exposure at or above that Load level
  - b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
  - a. The estimated number and type of customers affected

- b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

### III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
  - a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
  - b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

**C. Measures**

- M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.
- M2.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.
- M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- M4.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.
- M5.** Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.
- M6.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.
- M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.
- M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Enforcement Authority**

Regional Entity

**1.2 Compliance Monitoring Period and Reset Timeframe**

Not applicable.



### **1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### **1.4 Data Retention**

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

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

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

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

### **1.5 Additional Compliance Information**

None

2. Violation Severity Levels

|           | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|-----------|--|--|---|--|
| <b>R1</b> | The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.  | The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.  | The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.   | The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6.<br><br>OR<br><br>The responsible entity's System model did not represent projected System conditions as described in Requirement R1.<br><br>OR<br><br>The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan. |
| <b>R2</b> | The responsible entity failed to comply with Requirement R2, Part 2.6.   | The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.   | The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.                 | The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7.<br><br>OR<br><br>The responsible entity does not have a completed annual Planning Assessment.  |
| <b>R3</b> | The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5. | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.   |

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|           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----------|---|--|--|---|
|           |   | <p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.</p>   | <p>the categories (P2 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</p>   | <p>OR</p> <p>The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>  |
| <b>R4</b> | <p>The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.</p> | <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.</p> | <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.</p> | <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p> |
| <b>R5</b> | N/A   | N/A  | N/A  | <p>The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.</p>  |
| <b>R6</b> | N/A   | N/A  | N/A  | <p>The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.</p>   |

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|           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----------|---|--|--|---|
| <b>R7</b> | N/A   | N/A  | N/A  | The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.   |
| <b>R8</b> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.</p> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.</p> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.</p> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.</p> <p>OR</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.</p> |

**E. Regional Variances**

None.

**Version History**

| Version | Date  | Action  | Change Tracking                     |
|---------|---|---|-------------------------------------|
| 0       | April 1, 2005                                   | Effective Date  | New                                 |
| 0       | February 8, 2005                                | BOT Approval  | Revised                             |
| 0       | June 3, 2005                                    | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata                              |
| 0       | July 24, 2007                                   | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.   | Errata                              |
| 0.1     | October 29, 2008                                | BOT adopted errata changes; updated version number to "0.1"   | Errata                              |
| 0.1     | May 13, 2009                                    | FERC Approved – Updated Effective Date and Footer   | Revised                             |
| 1       | Approved by Board of Trustees February 17, 2011 | Revised footnote 'b' pursuant to FERC Order RM06-16-009   | Revised (Project 2010-11)           |
| 2       | August 4, 2011                                  | Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.                   | Project 2006-02 – complete revision |
| 2       | August 4, 2011                                  | Adopted by Board of Trustees  |                                     |
| 1       | April 19, 2012                                  | FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693. |                                     |
| 3       | February 7, 2013                                | Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.                   |                                     |
| 4       | February 7, 2013                                | Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.                                       |                                     |
| 4       | October 17, 2013                                | FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).  |                                     |
| 4       | May 6, 2014                                     | The NERC Board of Trustees adopted a revision to the VRF of Requirement 1 from Medium to High in TPL-001-4.   |                                     |

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|------|-----|---------------------------------------|--|
| 4(X) | TBD | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|------|-----|---------------------------------------|--|

## A. Introduction

1. **Title:** Transmission System Planning Performance Requirements
2. **Number:** TPL-001-4(X)
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**
  - 4.1. **Functional Entity**
    - 4.1.1. Planning Coordinator.
    - 4.1.2. Transmission Planner.
5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4(X), Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4(X):

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

## B. Requirements

- R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 1.1.** System models shall represent:
- 1.1.1.** Existing Facilities
  - 1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
  - 1.1.3.** New planned Facilities and changes to existing Facilities
  - 1.1.4.** Real and reactive Load forecasts
  - 1.1.5.** Known commitments for Firm Transmission Service and Interchange
  - 1.1.6.** Resources (supply or demand side) required for Load
- R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 2.1.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:
- 2.1.1.** System peak Load for either Year One or year two, and for year five.
  - 2.1.2.** System Off-Peak Load for one of the five years.
  - 2.1.3.** P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.
  - 2.1.4.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :
    - Real and reactive forecasted Load.
    - Expected transfers.
    - Expected in service dates of new or modified Transmission Facilities.
    - Reactive resource capability.
    - Generation additions, retirements, or other dispatch scenarios.



- Controllable Loads and Demand Side Management.
  - Duration or timing of known Transmission outages.
- 2.1.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
- 2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
- 2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.
- 2.3.** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
- 2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:
- 2.4.1.** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
- 2.4.2.** System Off-Peak Load for one of the five years.
- 2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
- Load level, Load forecast, or dynamic Load model assumptions.
  - Expected transfers.
  - Expected in service dates of new or modified Transmission Facilities.
  - Reactive resource capability.
  - Generation additions, retirements, or other dispatch scenarios.

- 2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.
- 2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:
- 2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- 2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.
- 2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
- 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
  - Installation, modification, or removal of Protection Systems or ~~Special Protection System~~ Remedial Action Schemes
  - Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
  - Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
  - Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
  - Use of rate applications, DSM, new technologies, or other initiatives.
- 2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.
- 2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

- 2.7.4.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
- 2.8.** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

  - 2.8.1.** List System deficiencies and the associated actions needed to achieve required System performance.
  - 2.8.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
- R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

  - 3.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.
  - 3.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.
  - 3.3.** Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

    - 3.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

      - 3.3.1.1.** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
      - 3.3.1.2.** Tripping of Transmission elements where relay loadability limits are exceeded.
    - 3.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
  - 3.4.** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies

to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

- 3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
- 3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.
- R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
  - 4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.
    - 4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a ~~Special Protection System~~ Remedial Action Scheme is not considered pulling out of synchronism.
    - 4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.
    - 4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.
  - 4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.
  - 4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :
    - 4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
      - 4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
      - 4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or

assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

- 4.3.1.3.** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
    - 4.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.
  - 4.4.** Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
    - 4.4.1.** Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
  - 4.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.
- R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- R7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [*Violation Risk Factor: Low*] [*Time Horizon: Long-term Planning*]
- R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- 8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide

a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

**Steady State & Stability:**

- a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
- b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
- c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
- d. Simulate Normal Clearing unless otherwise specified.
- e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

**Steady State Only:**

- f. Applicable Facility Ratings shall not be exceeded.
- g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
- h. Planning event P0 is applicable to steady state only.
- i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

**Stability Only:**

- j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

| Category   | Initial Condition | Event <sup>1</sup>  | Fault Type <sup>2</sup> | BES Level <sup>3</sup> | Interruption of Firm Transmission Service Allowed <sup>4</sup> | Non-Consequential Load Loss Allowed |
|--|-------------------|---|-------------------------|------------------------|--|-------------------------------------|
| <b>P0</b><br>No Contingency                              | Normal System     | None  | N/A                     | EHV, HV                | No   | No                                  |
| <b>P1</b><br>Single Contingency                          | Normal System     | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup> | 3Ø                      | EHV, HV                | No <sup>9</sup>  | No <sup>12</sup>                    |
|  |                   | 5. Single Pole of a DC line   | SLG                     |                        |  |                                     |
| <b>P2</b><br>Single Contingency                          | Normal System     | 1. Opening of a line section w/o a fault <sup>7</sup>   | N/A                     | EHV, HV                | No <sup>9</sup>  | No <sup>12</sup>                    |
|  |                   | 2. Bus Section Fault  | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
|  |                   |   |                         | HV                     | Yes  | Yes                                 |
|  |                   | 3. Internal Breaker Fault <sup>8</sup><br>(non-Bus-tie Breaker)   | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
| HV   | Yes               |   |                         | Yes                    |  |                                     |
| 4. Internal Breaker Fault (Bus-tie Breaker) <sup>8</sup> | SLG               | EHV, HV   | Yes                     | Yes                    |  |                                     |

**Standard TPL-001-4(X) — Transmission System Planning Performance Requirements**

| Category  | Initial Condition  | Event <sup>1</sup>  | Fault Type <sup>2</sup> | BES Level <sup>3</sup> | Interruption of Firm Transmission Service Allowed <sup>4</sup> | Non-Consequential Load Loss Allowed |
|---|--|---|-------------------------|------------------------|--|-------------------------------------|
| <b>P3</b><br>Multiple Contingency   | Loss of generator unit followed by System adjustments <sup>9</sup>   | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup>   | 3Ø                      | EHV, HV                | No <sup>9</sup>  | No <sup>12</sup>                    |
|   |  | 5. Single pole of a DC line   | SLG                     |                        |  |                                     |
| <b>P4</b><br>Multiple Contingency<br><i>(Fault plus stuck breaker<sup>10</sup>)</i> | Normal System  | Loss of multiple elements caused by a stuck breaker <sup>10</sup> (non-Bus-tie Breaker) attempting to clear a Fault on one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup><br>5. Bus Section                      | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
|   |  |   |                         | HV                     | Yes  | Yes                                 |
|   |  | 6. Loss of multiple elements caused by a stuck breaker <sup>10</sup> (Bus-tie Breaker) attempting to clear a Fault on the associated bus  | SLG                     | EHV, HV                | Yes  | Yes                                 |
| <b>P5</b><br>Multiple Contingency<br><i>(Fault plus relay failure to operate)</i>   | Normal System  | Delayed Fault Clearing due to the failure of a non-redundant relay <sup>13</sup> protecting the Faulted element to operate as designed, for one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer <sup>5</sup><br>4. Shunt Device <sup>6</sup><br>5. Bus Section | SLG                     | EHV                    | No <sup>9</sup>  | No                                  |
|   |  |   |                         | HV                     | Yes  | Yes                                 |
| <b>P6</b><br>Multiple Contingency<br><i>(Two overlapping singles)</i>               | Loss of one of the following followed by System adjustments. <sup>9</sup><br>1. Transmission Circuit<br>2. Transformer <sup>5</sup><br>3. Shunt Device <sup>6</sup><br>4. Single pole of a DC line | Loss of one of the following:<br>1. Transmission Circuit<br>2. Transformer <sup>5</sup><br>3. Shunt Device <sup>6</sup>   | 3Ø                      | EHV, HV                | Yes  | Yes                                 |
|   |  | 4. Single pole of a DC line   | SLG                     |                        |  |                                     |



**Standard TPL-001-4(X) — Transmission System Planning Performance Requirements**

| Category   | Initial Condition | Event <sup>1</sup>  | Fault Type <sup>2</sup> | BES Level <sup>3</sup> | Interruption of Firm Transmission Service Allowed <sup>4</sup> | Non-Consequential Load Loss Allowed |
|--|-------------------|---|-------------------------|------------------------|--|-------------------------------------|
| <b>P7</b><br>Multiple Contingency<br><i>(Common Structure)</i> | Normal System     | The loss of:<br>1. Any two adjacent (vertically or horizontally) circuits on common structure <sup>11</sup><br>2. Loss of a bipolar DC line | SLG                     | EHV, HV                | Yes  | Yes                                 |

**Table 1 – Steady State & Stability Performance Extreme Events**

|  |   |
|--|---|
| <p><b>Steady State &amp; Stability</b><br/>                 For all extreme events evaluated:</p> <ol style="list-style-type: none"> <li>a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.</li> <li>b. Simulate Normal Clearing unless otherwise specified.</li> </ol>   |   |
| <p><b>Steady State</b></p> <ol style="list-style-type: none"> <li>1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.</li> <li>2. Local area events affecting the Transmission System such as:                         <ol style="list-style-type: none"> <li>a. Loss of a tower line with three or more circuits.<sup>11</sup></li> <li>b. Loss of all Transmission lines on a common Right-of-Way<sup>11</sup>.</li> <li>c. Loss of a switching station or substation (loss of one voltage level plus transformers).</li> <li>d. Loss of all generating units at a generating station.</li> <li>e. Loss of a large Load or major Load center.</li> </ol> </li> <li>3. Wide area events affecting the Transmission System based on System topology such as:                         <ol style="list-style-type: none"> <li>a. Loss of two generating stations resulting from conditions such as:                                 <ol style="list-style-type: none"> <li>i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.</li> <li>ii. Loss of the use of a large body of water as the cooling source for generation.</li> <li>iii. Wildfires.</li> <li>iv. Severe weather, e.g., hurricanes, tornadoes, etc.</li> <li>v. A successful cyber attack.</li> <li>vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.</li> </ol> </li> <li>b. Other events based upon operating experience that may result in wide area disturbances.</li> </ol> </li> </ol> | <p><b>Stability</b></p> <ol style="list-style-type: none"> <li>1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.</li> <li>2. Local or wide area events affecting the Transmission System such as:                         <ol style="list-style-type: none"> <li>a. 3Ø fault on generator with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>b. 3Ø fault on Transmission circuit with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>c. 3Ø fault on transformer with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>d. 3Ø fault on bus section with stuck breaker<sup>10</sup> or a relay failure<sup>13</sup> resulting in Delayed Fault Clearing.</li> <li>e. 3Ø internal breaker fault.</li> <li>f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</li> </ol> </li> </ol> |

**Table 1 – Steady State & Stability Performance Footnotes  
(Planning Events and Extreme Events)**

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3 $\emptyset$ ) are the fault types that must be evaluated in Stability simulations for the event described. A 3 $\emptyset$  or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
  - a. Date, time, and location for the meeting
  - b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
  - c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
  - a. System Load level and estimated annual hours of exposure at or above that Load level
  - b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
  - a. The estimated number and type of customers affected

- b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

### III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
  - a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
  - b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

**C. Measures**

- M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.
- M2.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.
- M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- M4.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.
- M5.** Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.
- M6.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.
- M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.
- M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Enforcement Authority**

Regional Entity

**1.2 Compliance Monitoring Period and Reset Timeframe**

Not applicable.

### **1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### **1.4 Data Retention**

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

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

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

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

### **1.5 Additional Compliance Information**

None

2. Violation Severity Levels

|           | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|-----------|--|--|---|--|
| <b>R1</b> | The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.  | The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.  | The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.   | The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6.<br><br>OR<br><br>The responsible entity's System model did not represent projected System conditions as described in Requirement R1.<br><br>OR<br><br>The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan. |
| <b>R2</b> | The responsible entity failed to comply with Requirement R2, Part 2.6.   | The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.   | The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.                 | The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7.<br><br>OR<br><br>The responsible entity does not have a completed annual Planning Assessment.  |
| <b>R3</b> | The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5. | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.   |



**Standard TPL-001-4(X) — Transmission System Planning Performance Requirements**

|           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----------|---|--|--|---|
|           |   | <p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.</p>   | <p>the categories (P2 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</p>   | <p>OR</p> <p>The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>  |
| <b>R4</b> | <p>The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.</p> | <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.</p> | <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.</p> | <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p> |
| <b>R5</b> | N/A   | N/A  | N/A  | <p>The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.</p>  |
| <b>R6</b> | N/A   | N/A  | N/A  | <p>The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.</p>   |

**Standard TPL-001-4(X) — Transmission System Planning Performance Requirements**

|           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----------|---|--|--|---|
| <b>R7</b> | N/A   | N/A  | N/A  | The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.   |
| <b>R8</b> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.</p> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.</p> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.</p> | <p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.</p> <p>OR</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.</p> |

**E. Regional Variances**

None.

**Version History**

| Version | Date  | Action  | Change Tracking                     |
|---------|---|---|-------------------------------------|
| 0       | April 1, 2005                                   | Effective Date  | New                                 |
| 0       | February 8, 2005                                | BOT Approval  | Revised                             |
| 0       | June 3, 2005                                    | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata                              |
| 0       | July 24, 2007                                   | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.   | Errata                              |
| 0.1     | October 29, 2008                                | BOT adopted errata changes; updated version number to "0.1"   | Errata                              |
| 0.1     | May 13, 2009                                    | FERC Approved – Updated Effective Date and Footer   | Revised                             |
| 1       | Approved by Board of Trustees February 17, 2011 | Revised footnote 'b' pursuant to FERC Order RM06-16-009   | Revised (Project 2010-11)           |
| 2       | August 4, 2011                                  | Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.                   | Project 2006-02 – complete revision |
| 2       | August 4, 2011                                  | Adopted by Board of Trustees  |                                     |
| 1       | April 19, 2012                                  | FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693. |                                     |
| 3       | February 7, 2013                                | Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.                   |                                     |
| 4       | February 7, 2013                                | Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.                                       |                                     |
| 4       | October 17, 2013                                | FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).  |                                     |
| 4       | May 6, 2014                                     | The NERC Board of Trustees adopted a revision to the VRF of Requirement 1 from Medium to High in TPL-001-4.   |                                     |

**Standard TPL-001-4(X) — Transmission System Planning Performance Requirements**

|             |            |  |   |
|-------------|------------|--|---|
|             |            |  |   |
| <u>4(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0b(X)
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities.

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.
    - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

## **Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

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- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0b(X)\_R1 and TPL-002-0b(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0b(X)\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

**Compliance Monitor:** Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date               | Action   | Change Tracking  |
|---------|--------------------|--|--|
| 0       | February 8, 2005   | Adopted by NERC Board of Trustees  | New  |
| 0       | April 1, 2005      | Effective Date   | New  |
| 0a      | July 30, 2008      | Adopted by NERC Board of Trustees  | New  |
| 0a      | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0b      | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation   |
| 0b      | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation   |
| 0b(X)   | TBD                | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**Table I. Transmission System Standards — Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |



## Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element

|   |   |                |                |                         |                |  |
|---|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <p>5. Breaker (failure or internal Fault)</p> <hr style="border-top: 1px dashed black;"/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Appendix 1

### Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### Requirement R1.3.2

#### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2  
Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

## Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p style="padding-left: 40px;"><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| Background Information for Interpretation  |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> <li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li> <li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li> <li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li> </ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> </ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>4. Single Pole (dc) Line</li> </ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| Conclusion   |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

**A. Introduction**

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0b(X)
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities.

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.
    - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

## **Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

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- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0b(X)\_R1 and TPL-002-0b(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0b(X)\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

**Compliance Monitor:** Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.



**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version      | Date               | Action   | Change Tracking   |
|--------------|--------------------|--|---|
| 0            | February 8, 2005   | Adopted by NERC Board of Trustees  | New   |
| 0            | April 1, 2005      | Effective Date   | New   |
| 0a           | July 30, 2008      | Adopted by NERC Board of Trustees  | New   |
| 0a           | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised   |
| 0b           | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation  |
| 0b           | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation  |
| <u>0b(X)</u> | <u>TBD</u>         | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**Table I. Transmission System Standards — Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

## Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element

|   |   |   |
|---|---|---|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol> <hr style="border-top: 1px dashed black;"/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|---|---|---|

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Appendix 1

### Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### Requirement R1.3.2

#### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2  
Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

## Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p style="padding-left: 40px;"><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| Background Information for Interpretation  |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> <li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li> <li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li> <li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li> </ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> </ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>4. Single Pole (dc) Line</li> </ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| Conclusion   |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.



## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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### A. Introduction

1. **Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. **Number:** TPL-003-0b(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** April 23, 2010

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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- R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
  - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
  - R1.3.11.** Include the effects of existing and planned control devices.
  - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0b(X)\_R1 and TPL-003-0b(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0b(X)\_R3.

### D. Compliance

- 1. Compliance Monitoring Process**

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

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**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 0       | February 8, 2005 | Adopted by NERC Board of Trustees  | New  |
| 0       | April 1, 2005    | Effective Date   | New  |
| 0       | April 1, 2005    | Add parenthesis to item “e” on page 8.   | Errata   |
| 0a      | July 30, 2008    | Adopted by NERC Board of Trustees  |  |
| 0a      | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0a      | April 23, 2010   | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation   |
| 0b      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees   |  |
| 0b      | June 20, 2013    | FERC order issued approving Interpretation   |  |
| 0b(X)   | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                                |
|--|--|---|--|--------------------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No           |
|  | Single Pole Block, Normal Clearing <sup>e</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>e</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | Bipolar Block, with Normal Clearing <sup>e</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>e</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
| 7. Transformer   | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |
| 8. Transmission Circuit  | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |
| 9. Bus Section   | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

|  |   |                |                |                         |                |  |
|--|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>  | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|  | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit  | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## **Appendix 1**

### **Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### **Requirement R1.3.2**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.



**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

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clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(X) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

## Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

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<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

### Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

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<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

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### A. Introduction

1. **Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. **Number:** TPL-003-0b(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** April 23, 2010

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

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- R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
  - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
  - R1.3.11.** Include the effects of existing and planned control devices.
  - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0b(X)\_R1 and TPL-003-0b(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0b(X)\_R3.

### D. Compliance

- 1. Compliance Monitoring Process**

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**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version      | Date             | Action   | Change Tracking   |
|--------------|------------------|--|---|
| 0            | February 8, 2005 | Adopted by NERC Board of Trustees  | New   |
| 0            | April 1, 2005    | Effective Date   | New   |
| 0            | April 1, 2005    | Add parenthesis to item “e” on page 8.   | Errata  |
| 0a           | July 30, 2008    | Adopted by NERC Board of Trustees  |   |
| 0a           | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised   |
| 0a           | April 23, 2010   | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation  |
| 0b           | February 7, 2013 | Interpretation adopted by NERC Board of Trustees   |   |
| 0b           | June 20, 2013    | FERC order issued approving Interpretation   |   |
| <u>0b(X)</u> | <u>TBD</u>       | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |



**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                                |
|--|--|---|--|--------------------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No           |
|  | Single Pole Block, Normal Clearing <sup>e</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>e</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | Bipolar Block, with Normal Clearing <sup>e</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>e</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
| 7. Transformer   | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |
| 8. Transmission Circuit  | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |
| 9. Bus Section   | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |

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|   |  |              |                |                         |                |  |
|---|--|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer   |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section   |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Appendix 1

### **Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### **Requirement R1.3.2**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

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### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(X) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.3.10. and/or TPL-004-0(X), Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a(X) Category C and TPL-004-0(X) Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

## Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0(X), Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.3.10. and/or TPL-004-0(X), Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.



### Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

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<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0(X), Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

**A. Introduction**

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0a(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** April 1, 2005

**B. Requirements**

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.
    - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
    - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
    - R1.3.8. Include the effects of existing and planned control devices.

**R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

**R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

**C. Measures**

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0a(X)\_R1.

**M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0a(X)\_R1.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Not applicable.

**E. Regional Differences**

**1.** None identified.

**Version History**

| Version | Date             | Action   | Change Tracking |
|---------|------------------|--|-----------------|
| 0       | April 1, 2005    | Effective Date                                   | New             |
| 0a      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees |                 |

**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

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|       |               |                                       |  |
|-------|---------------|---------------------------------------|--|
| 0a    | June 20, 2013 | Interpretation approved in FERC order |  |
| 0a(X) | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |   |                      |
|--|--|---|---|----------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers  | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No  | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>  | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>   | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section<br>2. Breaker (failure or internal Fault)   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No             |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>   | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |

## Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

|   |  |              |                |                         |                |  |
|---|--|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <hr/> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer   |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section   |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.



More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

## Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

## Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## **Standard TPL-004-0a(x) — System Performance Following Extreme BES Events**

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

**A. Introduction**

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0a(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** April 1, 2005

**B. Requirements**

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.
    - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
    - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
    - R1.3.8. Include the effects of existing and planned control devices.

**R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

**R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

**C. Measures**

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0a(X)-R1.

**M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0a(X)-R1.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Not applicable.

**E. Regional Differences**

**1.** None identified.

**Version History**

| Version | Date             | Action   | Change Tracking |
|---------|------------------|--|-----------------|
| 0       | April 1, 2005    | Effective Date                                   | New             |
| 0a      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees |                 |

**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

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|                       |                     |   |  |
|-----------------------|---------------------|---|--|
| 0a                    | June 20, 2013       | Interpretation approved in FERC order                 |  |
| <a href="#">0a(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a> | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |



## Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

|   |   |  |
|---|---|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant <del>Special Protection System (or Remedial Action Scheme)</del> in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|---|---|--|

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

# Unofficial Comment Form

## Project 2010-05.2 Special Protection Systems Phase 2 of Protection Systems

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the proposed definition of Remedial Action Scheme (RAS). The electronic comment form must be completed by **8 p.m. Eastern, Friday, July 25, 2014**.

If you have questions, please contact [Al.McMeekin@nerc.net](mailto:Al.McMeekin@nerc.net) or by telephone at (803) 530-1963.

The project page may be accessed by clicking [here](#).

### Background Information

The existing NERC Glossary of Terms definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS or RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS or RAS. The actions listed in the definition of “Special Protection System” and “Remedial Action Scheme” are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term; i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. This “broadness”; however, necessitates an exclusion list because without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

**Note:** The term “**Remedial Action Scheme**” (“**RAS**”) is and will be used throughout the documents associated with this Project to reflect the proposed retirement of the term “Special Protection System” (“SPS”).

## Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Do you agree that using a single term; i.e., RAS, and clarifying its definition will lead to more consistent application of the related NERC Reliability Standards? If not, please provide specific suggestions and rationale.

Yes

No

Comments:

2. Are there additional corrective actions that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale.

Yes

No

Comments:

3. Are there additional objectives that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale.

Yes

No

Comments:

4. Do you agree with the exclusion list in the proposed definition of RAS? If not, please provide specific suggestions and rationale.

Yes

No

Comments:

5. Do you agree with the time frames in the proposed Implementation Plan associated with the proposed definition of RAS? Please provide specific comments in support of your position.

Yes

No

Comments:



## Standards Authorization Request Form

When completed, email this form to:

[Valerie.Agnew@nerc.net](mailto:Valerie.Agnew@nerc.net)

For questions about this form or for assistance in completing the form, call Valerie Agnew at 404-446-2566.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

### Request to propose a new or a revision to a Reliability Standard

|   |   |         |                      |
|---|---|---------|----------------------|
| Proposed Project Number and Name                                  | Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)  |         |                      |
| Proposed Project Purpose:   | Revise NERC Glossary of Terms definition: Special Protection System (SPS)<br>Revise SPS-related Reliability Standards |         |                      |
| Date Submitted:   | 02/12/2014  |         |                      |
| SAR Requester Information   |   |         |                      |
| Name:   | Al McMeekin   |         |                      |
| Organization:   | NERC  |         |                      |
| Telephone:  | 404-446-9675  | E-mail: | Al.McMeekin@nerc.net |
| SAR Type (Check as many as applicable)                            |   |         |                      |
| <input checked="" type="checkbox"/> New Standard                  | <input checked="" type="checkbox"/> Withdrawal of existing Standard   |         |                      |
| <input checked="" type="checkbox"/> Revision to existing Standard | <input type="checkbox"/> Urgent Action  |         |                      |

SAR Information

Industry Need (What is the industry problem this request is trying to solve?):

The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or, as used in the Western Interconnection, a Remedial Action Scheme (RAS), lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified three of the SPS-related Reliability Standards (PRC-012-0, PRC-013-0, and PRC-014-0) as fill-in-the-blank standards because they are applicable to the Regional Reliability Organizations (RROs). Consequently, the Commission did not approve or remand them, rendering them neither mandatory nor enforceable.

This project also addresses, in part, four recommendations related to identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event.

NOTE: Detailed information is included in the NERC Planning Committee report “Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards” Revision 0.1 – April 2013.

Purpose or Goal (How does this request propose to address the problem described above?):

- 1) Establish a definition of an SPS or RAS that provides the specificity needed to consistently identify and classify protection schemes as SPS or RAS across all eight NERC Regions, thereby promoting the consistent application of the NERC Reliability Standards related to SPS.
- 2) Correct the applicability of the NERC Reliability Standards related to SPS/RAS by assigning responsibilities to the specific users, owners, and operators of the Bulk-Power System rather than the RROs.
- 3) Develop continent-wide standards to address all aspects of SPS/RAS, including but not limited to, the:
  - planning, coordination, and design of SPS/RAS,
  - review, assessment, and documentation of SPS/RAS,
  - operational considerations for monitoring, status notification, and response to failures,
  - analysis of SPS/RAS operations, and defining and reporting of SPS/RAS misoperations,
  - testing of SPS/RAS, and maintenance of any non-protection system components used.

| SAR Information  |
|--|
| Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):  |
| Successful implementation of a modified definition for an SPS/RAS, with the revised SPS/RAS-related Reliability Standards will improve Bulk-Power System reliability by providing continent-wide consistency in the identification and classification of SPS or RAS, and by promoting the consistent application of the related Reliability Standards.   |
| Brief Description (Provide a paragraph that describes the scope of this standard action.)  |
| <p>The project will develop a revised definition of SPS or RAS, as well as revise the NERC Reliability Standards that address the:</p> <ul style="list-style-type: none"> <li>• review of new or modified SPS/RAS,</li> <li>• annual assessments of SPS/RAS in transmission planning studies,</li> <li>• periodic comprehensive SPS/RAS assessments,</li> <li>• analysis and reporting of SPS/RAS misoperations,</li> <li>• maintenance, testing and operational aspects of SPS/RAS.</li> </ul>  |
| Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)   |
| <p>The SDT will revise the definition of SPS/RAS to provide the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS/RAS across the eight NERC Regions.</p> <p>The SDT will revise or retire the six existing SPS/RAS-related Reliability Standards:</p> <ul style="list-style-type: none"> <li>• PRC-012-0 Special Protection System Review Procedure</li> <li>• PRC-013-0 Special Protection System Database</li> <li>• PRC-014-0 Special Protection System Assessment</li> <li>• PRC-015-0 Special Protection System Data and Documentation</li> <li>• PRC-016-0.1 Special Protection System Misoperations</li> <li>• PRC-017-0 Special Protection System Maintenance and Testing</li> </ul> |

### SAR Information

The SDT will correct the applicability in PRC-012-0, PRC-013-0, and PRC-014-0 by assigning the requirements to the specific users, owners, and operators of the Bulk Power System.

The SDT will combine appropriate requirements from PRC-012-0, PRC-013-0, PRC-014-0, PRC-015-0, PRC-016-0.1, and PRC-017-0 into one or more Reliability Standard(s). The new standard(s) will provide specific requirements for:

- review of new or modified SPS/RAS;
- annual assessments of SPS/RAS in transmission planning studies;
- periodic comprehensive SPS/RAS assessments;
- design of SPS/RAS;
- operations and misoperations;
- maintenance and testing of SPS/RAS; and
- maintenance and testing of non-Protection System components used in SPS/RAS; and
- coordination of SPS/RAS with other SPS/RAS, UFLS, UVLS, and Protection Systems.

Due to the significant difference between Protection Systems and SPS, the subject of SPS misoperation is not addressed in the revision of Reliability Standard PRC-004. This SDT will develop a definition for SPS/RAS misoperation and revise PRC-016-0.1. The new Reliability Standard will provide specific requirements for the analysis of SPS operations and reporting of SPS misoperations.

The SDT will address the complexity of maintaining and testing SPS, as well as the maintenance and testing of non-Protection System components used in SPS in a Reliability Standard. This SDT will coordinate with the PRC-005-4 SDT to prevent any overlaps or gaps in coverage.

The SDT also will consider operational considerations for monitoring, status notification, and response to failures of SPS/RAS; and, if necessary, modify other related standards.

The SDT will retire requirements that are administrative in nature that are not necessary for reliability of the Bulk-Power System, or that are superseded by other requirements; i.e., the new Reliability Standards will qualify as steady-state.

No market interface impacts are anticipated.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

|   |   |
|---|---|
| <input checked="" type="checkbox"/> Reliability Coordinator | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.                              |
| <input checked="" type="checkbox"/> Balancing Authority     | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.                     |
| <input type="checkbox"/> Interchange Authority              | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas. |
| <input checked="" type="checkbox"/> Planning Coordinator    | Assesses the longer-term reliability of its Planning Coordinator Area.  |
| <input type="checkbox"/> Resource Planner                   | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.   |
| <input checked="" type="checkbox"/> Transmission Planner    | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.   |
| <input type="checkbox"/> Transmission Service Provider      | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).   |
| <input checked="" type="checkbox"/> Transmission Owner      | Owns and maintains transmission facilities.   |
| <input checked="" type="checkbox"/> Transmission Operator   | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.   |
| <input checked="" type="checkbox"/> Distribution Provider   | Delivers electrical energy to the End-use customer.   |
| <input checked="" type="checkbox"/> Generator Owner         | Owns and maintains generation facilities.   |
| <input checked="" type="checkbox"/> Generator Operator      | Operates generation unit(s) to provide real and reactive power.   |
| <input type="checkbox"/> Purchasing-Selling Entity          | Purchases or sells energy, capacity, and necessary reliability-related services as required.  |
| <input type="checkbox"/> Market Operator                    | Interface point for reliability functions with commercial functions.  |

| Reliability Functions                        |   |
|--|---|
| <input type="checkbox"/> Load-Serving Entity | Secures energy and transmission service (and reliability-related services) to serve the End-use Customer. |

| Reliability and Market Interface Principles  |   |
|--|---|
| Applicable Reliability Principles (Check all that apply).  |   |
| <input checked="" type="checkbox"/>  | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.               |
| <input type="checkbox"/>   | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.                     |
| <input checked="" type="checkbox"/>  | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| <input checked="" type="checkbox"/>  | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.   |
| <input checked="" type="checkbox"/>  | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.  |
| <input type="checkbox"/>   | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.                  |
| <input checked="" type="checkbox"/>  | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.  |
| <input type="checkbox"/>   | 8. Bulk power systems shall be protected from malicious physical or cyber-attacks.  |
| Does the proposed Standard comply with all of the following Market Interface Principles?   |   |
| 1. A reliability standard shall not give any market participant an unfair competitive advantage.   | Enter (yes/no)<br>Yes   |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure.  | Yes   |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.  | Yes   |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes   |

| Reliability and Market Interface Principles   |   |
|---|---|
| Related Standards   |   |
| Standard No.  | Explanation   |
| IRO-005-3.1a  | The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.  |
| PRC-001-1.1   | The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.  |
| PRC-005-2   | The SDT may decide not to change this standard, or subsequently approved versions, but the SDT should keep the standard in mind to avoid any gaps or overlap between this standard and PRC-017-1. |
| PRC-010-1   | The SDT may adjust the definition of Special Protection System to include centrally-controlled undervoltage-based load shedding or exclude UVLS Programs.   |
| CIP-002, CIP-003, CIP-004, CIP-005, CIP-006 CIP-007, CIP-008, CIP-009, CIP-010 CIP-011, EOP-004, FAC-010, FAC-011, IRO-005, IRO-014, MOD-029, MOD-030, NUC-001, PRC-001, PRC-004-WECC, PRC-005, PRC-006, PRC-012, PRC-013, PRC-014, PRC-015, PRC-016, PRC-017, PRC-020, PRC-021, PRC-023, PRC-024, PRC-025, TOP-005, TPL-001, TPL-002, TPL-003, | The SDT will review all current standards that include the term SPS or RAS to ensure the modified term and definition are congruent.  |

Reliability and Market Interface Principles

TPL-004; NERC  
 Glossary of Terms:  
 Special Protection  
 System, Remedial  
 Action Scheme;  
 WECC Regional  
 Term:  
 Dependability-  
 Based  
 Misoperation,  
 WECC Regional  
 Term: Functionally  
 Equivalent RAS,  
 WECC Regional  
 Term: Security-  
 Based  
 Misoperation

Related SARs

| Project  | Explanation   |
|--|---|
| Project 2008-02 –<br>Undervoltage<br>Load Shedding | The UVLSSDT is recommending that Project 2010-05.2 – Special Protection Systems adjust the definition of Special Protection System to include centrally-controlled undervoltage-based load shedding or exclude UVLS Programs. |
|  |   |
|  |   |
|  |   |
|  |   |



| Regional Variances |  |
|--------------------|--|
| Region             | Explanation  |
| ERCOT              |  |
| FRCC               |  |
| MRO                |  |
| NPCC               |  |
| RFC                |  |
| SERC               |  |
| SPP                |  |
| WECC               | Communicate recommended changes to Regional Reliability Standard PRC-004-WECC-1, regional criteria PRC-(012 through 014)-WECC-CRT-2, and PRC-013 RAS Reporting Template; or, if necessary, incorporate a regional variance in the NERC Reliability Standards developed by this project. All changes to any WECC standards and documents will be coordinated with WECC. |

## Standards Authorization Request Form

When completed, email this form to:

[Valerie.Agnew@nerc.net](mailto:Valerie.Agnew@nerc.net)

For questions about this form or for assistance in completing the form, call Valerie Agnew at 404-446-2566.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

### Request to propose a new or a revision to a Reliability Standard

|   |   |         |                      |
|---|---|---------|----------------------|
| Proposed Project Number and Name                                  | Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)  |         |                      |
| Proposed Project Purpose:   | Revise NERC Glossary of Terms definition: Special Protection System (SPS)<br>Revise SPS-related Reliability Standards |         |                      |
| Date Submitted:   | 02/12/2014  |         |                      |
| SAR Requester Information   |   |         |                      |
| Name:   | Al McMeekin   |         |                      |
| Organization:   | NERC  |         |                      |
| Telephone:  | 404-446-9675  | E-mail: | Al.McMeekin@nerc.net |
| SAR Type (Check as many as applicable)                            |   |         |                      |
| <input checked="" type="checkbox"/> New Standard                  | <input checked="" type="checkbox"/> Withdrawal of existing Standard   |         |                      |
| <input checked="" type="checkbox"/> Revision to existing Standard | <input type="checkbox"/> Urgent Action  |         |                      |

## SAR Information

## Industry Need (What is the industry problem this request is trying to solve?):

The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or, as used in the Western Interconnection, a Remedial Action Scheme (RAS), lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified three of the SPS-related ~~standards~~ Reliability Standards (PRC-012-0, PRC-013-0, and PRC-014-0) as fill-in-the-blank standards because they are applicable to the Regional Reliability Organizations (RROs). Consequently, the Commission did not approve or remand them, rendering them neither mandatory nor enforceable.

This project also addresses, in part, four recommendations related to identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event.

NOTE: Detailed information is included in the NERC Planning Committee report “Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards” Revision 0.1 – April 2013.

## Purpose or Goal (How does this request propose to address the problem described above?):

- 1) Establish a definition of an SPS or RAS that provides the specificity needed to consistently identify and classify protection schemes as SPS or RAS across all eight NERC Regions, thereby promoting the consistent application of the NERC Reliability Standards related to SPS.
- 2) Correct the applicability of the NERC Reliability Standards related to SPS/RAS by assigning responsibilities to the specific users, owners, and operators of the Bulk-Power System rather than the RROs.
- 3) Develop continent-wide standards to address all aspects of SPS/RAS, including but not limited to, the:
  - planning, coordination, and design of SPS/RAS,
  - review, assessment, and documentation of SPS/RAS,
  - operational considerations for monitoring, status notification, and response to failures,
  - analysis of SPS/RAS operations, and defining and reporting of SPS/RAS misoperations,
  - testing of SPS/RAS, and maintenance of any non-protection system components used ~~in SPS~~.

## SAR Information

Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):

Successful implementation of a modified ~~SPS~~ definition ~~and~~ for an SPS/RAS, with the revised SPS ~~standards~~ /RAS-related Reliability Standards will improve Bulk-Power System reliability by providing continent-wide consistency in the identification and classification of SPS or RAS, and by promoting the consistent application of ~~NERC~~ the related Reliability Standards ~~related to SPS~~.

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

The project will develop a revised definition of SPS or RAS, as well as ~~standards~~ revise the NERC Reliability Standards that address the:

- review of new or modified SPS/RAS,
- annual assessments of SPS/RAS in transmission planning studies,
- periodic comprehensive SPS/RAS assessments,
- analysis and reporting of SPS/RAS misoperations,
- maintenance, testing and operational aspects of SPS/RAS.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The SDT will revise the definition of SPS/RAS to provide the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS ~~or~~ /RAS across the eight NERC Regions.

The SDT will revise or retire the six existing SPS ~~standards~~ /RAS-related Reliability Standards:

- PRC-012-0 Special Protection System Review Procedure
- PRC-013-0 Special Protection System Database
- PRC-014-0 Special Protection System Assessment
- PRC-015-0 Special Protection System ~~data~~ Data and Documentation
- PRC-016-0.1 Special Protection System Misoperations
- PRC-017-0 Special Protection System Maintenance and Testing

## SAR Information

The SDT will correct the applicability in PRC-012-0, PRC-013-0, and PRC-014-0 by assigning the requirements to the specific users, owners, and operators of the ~~bulk power system~~ Bulk Power System.

The SDT will combine appropriate requirements from PRC-012-0, PRC-013-0, PRC-014-0, PRC-015-0, PRC-016-0.1, and PRC-~~015~~017-0 into one or more Reliability Standard-(s). The new standard(s) will provide specific requirements for:

- review of new or modified SPS/RAS;
- annual assessments of SPS/RAS in transmission planning studies;
- periodic comprehensive SPS/RAS assessments;
- design of SPS;/RAS;
- operations and misoperations;
- maintenance and testing of SPS/RAS; and
- maintenance and testing of non-Protection System components used in SPS/RAS; and
- coordination of SPS/RAS with other SPS/RAS, UFLS, UVLS, and Protection Systems.

Due to the significant difference between Protection Systems and SPS, the subject of SPS misoperation is not addressed in the revision of Reliability Standard PRC-004. This SDT will develop a definition for SPS/RAS misoperation and revise PRC-016-0.1. The new Reliability Standard will provide specific requirements for the analysis of SPS operations and reporting of SPS misoperations.

The SDT will address the complexity of maintaining and testing SPS, as well as the maintenance and testing of non-Protection System components used in SPS in a Reliability Standard. -This SDT will coordinate with the PRC-005-4 SDT to prevent any overlaps or gaps in coverage.

The SDT also will consider operational considerations for monitoring, status notification, and response to failures of SPS/RAS; and, if necessary, modify other related standards.

The SDT will retire requirements that are administrative in nature that are not necessary for reliability of the Bulk-Power System, or that are superseded by other requirements; i.e., the new Reliability Standards will qualify as steady-state.

No market interface impacts are anticipated.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

|   |  |
|---|--|
| <input type="checkbox"/> <del>Regional Reliability Organization</del> | <del>Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.</del> |
| <input checked="" type="checkbox"/> Reliability Coordinator           | Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.   |
| <input checked="" type="checkbox"/> Balancing Authority               | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.  |
| <input type="checkbox"/> Interchange Authority                        | Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.                              |
| <input checked="" type="checkbox"/> Planning Coordinator              | Assesses the longer-term reliability of its Planning Coordinator Area.   |
| <input type="checkbox"/> Resource Planner                             | Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.  |
| <input checked="" type="checkbox"/> Transmission Planner              | Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.  |
| <input type="checkbox"/> Transmission Service Provider                | Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).  |
| <input checked="" type="checkbox"/> Transmission Owner                | Owns and maintains transmission facilities.  |
| <input checked="" type="checkbox"/> Transmission Operator             | Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.  |
| <input checked="" type="checkbox"/> Distribution Provider             | Delivers electrical energy to the End-use customer.  |
| <input checked="" type="checkbox"/> Generator Owner                   | Owns and maintains generation facilities.  |
| <input checked="" type="checkbox"/> Generator Operator                | Operates generation unit(s) to provide real and reactive power.  |

| Reliability Functions                              |   |
|--|---|
| <input type="checkbox"/> Purchasing-Selling Entity | Purchases or sells energy, capacity, and necessary reliability-related services as required.              |
| <input type="checkbox"/> Market Operator           | Interface point for reliability functions with commercial functions.                                      |
| <input type="checkbox"/> Load-Serving Entity       | Secures energy and transmission service (and reliability-related services) to serve the End-use Customer. |

| Reliability and Market Interface Principles  |   |
|--|---|
| Applicable Reliability Principles (Check all that apply).  |   |
| <input checked="" type="checkbox"/>  | 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.               |
| <input type="checkbox"/>   | 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.                     |
| <input checked="" type="checkbox"/>  | 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| <input checked="" type="checkbox"/>  | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.   |
| <input checked="" type="checkbox"/>  | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.  |
| <input type="checkbox"/>   | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.                  |
| <input checked="" type="checkbox"/>  | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.  |
| <input type="checkbox"/>   | 8. Bulk power systems shall be protected from malicious physical or cyber-attacks.  |
| Does the proposed Standard comply with all of the following Market Interface Principles?         |   |
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. | Enter (yes/no)<br>Yes   |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure.      | Yes   |

| Reliability and Market Interface Principles  |     |
|--|-----|
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.  | Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes |

| Related Standards  |   |
|--|---|
| Standard No.   | Explanation   |
| IRO-005-3.1a   | The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.  |
| PRC-001-1.1  | The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.  |
| PRC-005-2  | The SDT may decide not to change this standard, or subsequently approved versions, but the SDT should keep the standard in mind to avoid any gaps or overlap between this standard and PRC-017-1. |
| <u>PRC-010-1</u>   | <u>The SDT may adjust the definition of Special Protection System to include centrally-controlled undervoltage-based load shedding or exclude UVLS Programs.</u>                                  |
| <u>CIP-002, CIP-003, CIP-004, CIP-005, CIP-006 CIP-007, CIP-008, CIP-009, CIP-010 CIP-011, EOP-004, FAC-010, FAC-011, IRO-005, IRO-014, MOD-029, MOD-030, NUC-001, PRC-001, PRC-004-WECC, PRC-005, PRC-006, PRC-012, PRC-013, PRC-014,</u> | <u>The SDT will review all current standards that include the term SPS or RAS to ensure the modified term and definition are congruent.</u>   |



Related Standards

[PRC-015, PRC-016, PRC-017, PRC-020, PRC-021, PRC-023, PRC-024, PRC-025, TOP-005, TPL-001, TPL-002, TPL-003, TPL-004; NERC Glossary of Terms: Special Protection System, Remedial Action Scheme; WECC Regional Term: Dependability-Based Misoperation, WECC Regional Term: Functionally Equivalent RAS, WECC Regional Term: Security-Based Misoperation](#)

Related SARs

| SAR-IDProject  | Explanation   |
|--|---|
| <a href="#">Project 2008-02 – Undervoltage Load Shedding</a> | <a href="#">The UVLSSDT is recommending that Project 2010-05.2 – Special Protection Systems adjust the definition of Special Protection System to include centrally-controlled undervoltage-based load shedding or exclude UVLS Programs.</a> |
|  |   |
|  |   |
|  |   |

Related Standards

| Related Standards |  |
|-------------------|--|
|                   |  |
|                   |  |
|                   |  |
|                   |  |

| Regional Variances |   |
|--------------------|---|
| Region             | Explanation   |
| ERCOT              |   |
| FRCC               |   |
| MRO                |   |
| NPCC               |   |
| RFC                |   |
| SERC               |   |
| SPP                |   |
| WECC               | <u>Communicate recommended changes to Regional Reliability Standard PRC-004-WECC-1, regional criteria PRC-(012 through 014)-WECC-CRT-2, and PRC-013 RAS Reporting Template; or, if necessary, incorporate a regional variance in the NERC Reliability Standards developed by this project. All changes to any WECC standards and documents will be coordinated with WECC.</u> |

# Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards

This document provides a summary of the occurrences of “Special Protection System” (“SPS”) and “Remedial Action Scheme” (“RAS”) in the existing NERC Reliability Standards to assist entities in assessing the impact of the proposed definition of “Remedial Action Scheme.” The existing Reliability Standards and certain NERC Glossary of Terms use the terms interchangeably.<sup>1</sup> Changes are proposed in this Project for each applicable standard and NERC Glossary term to align the use of the terminology in each instance. Where only the term SPS occurs, it was replaced with RAS. Where both terms, SPS and RAS, occur, the drafting team deleted the references to SPS. Where only the term RAS occurs, no change was made. In all cases, entities should apply the proposed definition of RAS to its own schemes, and determine any impact.

## General Description of Definition Change

The revised definition of RAS will create one definition to replace both existing definitions in the NERC Glossary of Terms, for use throughout the NERC Reliability Standards. The revised definition of RAS addresses ambiguities within the existing definition and provides clarity to promote consistency in the application of the standards by the responsible entities and the auditing of the standards by compliance staff. The revised definition of RAS recasts the existing definition of SPS to:

- more precisely describe the objectives of the schemes;
- more precisely describe exclusions;
- state the relationship between Protection Systems and RAS; and
- clarify that centrally controlled undervoltage-based load shedding is included in the definition.

## Uses of SPS and RAS in Existing Reliability Standards and NERC Glossary of Terms

The table below includes each occurrence of SPS and RAS found in the applicability sections, requirements, tables, and attachments of the existing NERC Reliability Standards (as of May 16, 2014). The table does not reflect any associated occurrences in other sections of the standard such as the measures, compliance information, and Violation Severity Levels. All occurrences have been reflected in the separate document *Revised Reliability Standards for the Revised Definition of “Remedial Action Scheme.”*

<sup>1</sup> NERC, *Reliability Standards for the Bulk Electric Systems of North America* (Updated May 16, 2014).

| Standard No.                    | Existing Standard Language   |
|---------------------------------|--|
| <p>CIP-002-3<br/>CIP-002-3b</p> | <p><b>B. Requirements</b></p> <p><b>R1.</b> Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.</p> <p style="padding-left: 40px;"><b>R1.1.</b> The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.</p> <p style="padding-left: 40px;"><b>R1.2.</b> The risk-based assessment shall consider the following assets:</p> <p style="padding-left: 80px;"><b>R1.2.6. Special Protection Systems</b> that support the reliable operation of the Bulk Electric System.</p>  |
| <p>CIP-002-5.1</p>              | <p><b>4. Applicability:</b></p> <p style="padding-left: 40px;"><b>4.1.2.</b><br/>Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:</p> <p style="padding-left: 80px;"><b>4.1.2.2.</b> Each <b>Special Protection System</b> or <b>Remedial Action Scheme</b> where the <b>Special Protection System</b> or <b>Remedial Action Scheme</b> is subject to one or more requirements in a NERC or Regional Reliability Standard.</p> <hr/> <p><b>B. Requirements and Measures</b></p> <p><b>R1.</b> Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [<i>Violation Risk Factor: High</i>][<i>Time Horizon: Operations Planning</i>]</p> <p style="padding-left: 40px;"><b>v. Special Protection Systems</b> that support the reliable operation of the Bulk Electric System;...</p> <hr/> <p><b>Attachment 1: Impact Rating Criteria</b></p> <p><b>2. Medium Impact Rating (M)</b></p> <p style="padding-left: 40px;"><b>2.9.</b> Each <b>Special Protection System (SPS)</b>, <b>Remedial Action Scheme (RAS)</b>, or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.</p> <hr/> <p><b>3. Low Impact Rating (L)</b></p> <p style="padding-left: 40px;"><b>3.5. Special Protection Systems</b> that support the reliable operation of the Bulk Electric System.</p> |

| Standard No.   | Existing Standard Language  |   |         |   |
|--|---|---|---------|---|
| <p>CIP-003-5<br/>CIP-004-5.1<br/>CIP-005-5<br/>CIP-006-5<br/>CIP-007-5<br/>CIP-008-5<br/>CIP-009-5<br/>CIP-010-1<br/>CIP-011-1</p> | <p>(All standards)</p> <p><b>4. Applicability:</b></p> <p><b>4.1.2.2.</b> Each <b>Special Protection System</b> or <b>Remedial Action Scheme</b> where the <b>Special Protection System</b> or <b>Remedial Action Scheme</b> is subject to one or more requirements in a NERC or Regional Reliability Standard.</p> <p><b>4.2.1.2.</b> Each <b>Special Protection System</b> or <b>Remedial Action Scheme</b> where the <b>Special Protection System</b> or <b>Remedial Action Scheme</b> is subject to one or more requirements in a NERC or Regional Reliability Standard.</p>  |   |         |   |
| <p>EOP-004-2</p>   | <p><b>Attachment 1: Reportable Events</b></p> <table border="1" data-bbox="363 768 1484 926"> <tr> <td data-bbox="363 768 805 926">BES Emergency resulting in automatic firm load shedding</td> <td data-bbox="805 768 912 926">DP, TOP</td> <td data-bbox="912 768 1484 926">Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <b>SPS/RAS</b>).</td> </tr> </table>  | BES Emergency resulting in automatic firm load shedding   | DP, TOP | Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <b>SPS/RAS</b> ). |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP   | Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or <b>SPS/RAS</b> ). |         |   |
| <p>FAC-010-2.1</p>   | <p><b>B. Requirements</b></p> <p><b>R3.</b> The Planning Authority’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:</p> <p><b>R3.4.</b> Allowed uses of <b>Special Protection Systems</b> or <b>Remedial Action Plans</b>.</p> <p><b>E. Regional Differences</b></p> <p><b>1.1.</b> As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:</p> <p><b>1.1.4</b> The failure of a circuit breaker associated with a <b>Special Protection System</b> to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.</p> |   |         |   |
| <p>FAC-011-2</p>   | <p><b>B. Requirements</b></p> <p><b>R3.</b> The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:</p> <p><b>R3.5.</b> Allowed uses of <b>Special Protection Systems</b> or <b>Remedial Action Plans</b>.</p> <p><b>E. Regional Differences</b></p> <p><b>1.1.</b> As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:</p> <p><b>1.1.4</b> The failure of a circuit breaker associated with a <b>Special Protection System</b> to operate when required following: the loss of any element without a Fault; or a</p>   |   |         |   |

| Standard No.               | Existing Standard Language   |
|----------------------------|--|
|                            | <p>permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.</p>   |
| <p><b>IRO-005-3.1a</b></p> | <p><b>B. Requirements:</b></p> <p><b>R1.</b> Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:</p> <p style="padding-left: 40px;"><b>R1.1.</b> Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and <b>Special Protection Systems</b>) and system loading.</p> <p><b>R9.</b> Whenever a <b>Special Protection System</b> that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that <b>Special Protection System</b> on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the <b>Special Protection System</b> including any degradation or potential failure to operate as expected.</p>  |
| <p><b>IRO-014-1</b></p>    | <p><b>B. Requirements</b></p> <p><b>R1.</b> The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.</p> <p style="padding-left: 40px;"><b>R1.1.</b> These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:</p> <p style="padding-left: 80px;"><b>R1.1.1.</b> Communications and notifications, including the conditions <b>[FN1]</b> under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.</p> <p><b>[FN1]:</b> Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of <b>special protection systems</b>, etc.</p> |
| <p><b>MOD-029-1a</b></p>   | <p><b>B. Requirements</b></p> <p style="padding-left: 40px;"><b>R1.1.8.</b> Uses <b>Special Protection System (SPS)</b> models where currently existing or projected for implementation within the studied time horizon.</p> <p style="padding-left: 40px;"><b>R2.2.</b> Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a <b>Special Protection System (SPS)</b>, set the TTC for the non-prevailing flow direction equal to the greater of the maximum</p>   |

| Standard No.   | Existing Standard Language  |
|--|---|
|  | <p>flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a <b>SPS</b>.</p>  |
| <p><b>MOD-030-02</b></p>                                       | <p><b>B. Requirements</b></p> <p><b>R2.1.1.1.</b> Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of <b>Special Protection Systems</b>.</p> <p><b>R2.1.2.1.</b> Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of <b>Special Protection Systems</b>.</p>   |
| <p><b>NUC-001-2.1</b></p>                                      | <p><b>B. Requirements</b></p> <p><b>R9.</b> The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2:</p> <p><b>R9.3.7.</b> Coordination of the NPIRs with transmission system <b>Special Protection Systems</b> and underfrequency and undervoltage load shedding programs.</p>  |
| <p><b>PRC-001-1.1</b></p>                                      | <p><b>B. Requirements</b></p> <p><b>R6.</b> Each Transmission Operator and Balancing Authority shall monitor the status of each <b>Special Protection System</b> in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.</p>  |
| <p><b>WECC Regional Standard</b><br/><b>PRC-004-WECC-1</b></p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Protection System and <b>Remedial Action Scheme</b> Misoperation</p> <p><b>2. Number:</b> PRC-004-WECC-1</p> <p><b>3. Purpose:</b> Regional Reliability Standard to ensure all transmission and generation Protection System and <b>Remedial Action Scheme (RAS)</b> Misoperations on Transmission Paths and <b>RAS</b> defined in section 4 are analyzed and/or mitigated.</p> <p><b>4. Applicability</b></p> <p><b>4.1.</b>Transmission Owners of selected WECC major transmission path facilities and <b>RAS</b> listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf</a> and “Major WECC <b>Remedial Action Schemes (RAS)</b>” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf</a>.</p> <p><b>4.2.</b>Generator Owners that own <b>RAS</b> listed in the Table titled “Major WECC <b>Remedial Action Schemes (RAS)</b>” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf</a>.</p> <p><b>4.3.</b>Transmission Operators that operate major transmission path facilities and <b>RAS</b> listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at</p> |



| Standard No. | Existing Standard Language  |
|--------------|---|
|              | <p data-bbox="362 375 1464 548"> <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf</a> and “Major WECC Remedial Action Schemes (RAS)” provided at <a href="http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf">http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf</a>.         </p> <p data-bbox="362 554 568 583"><b>B. Requirements</b></p> <p data-bbox="362 602 1479 705">           The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”         </p> <p data-bbox="362 722 1422 825"> <b>R.1.</b> System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]</i> </p> <p data-bbox="456 842 1430 909"> <b>R1.1.</b> System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.         </p> <p data-bbox="456 926 1463 1029"> <b>R1.2.</b> System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.         </p> <p data-bbox="362 1045 1474 1325"> <b>R.2.</b> Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:         </p> <p data-bbox="456 1341 1466 1585"> <b>R2.1.</b> If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners’ and Generator Owners’ discretion.         </p> <p data-bbox="456 1602 1479 1705"> <b>R2.2.</b> If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following.         </p> <p data-bbox="552 1722 1484 1860"> <b>R2.2.1.</b> Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.         </p> |

| Standard No.                  | Existing Standard Language   |
|-------------------------------|--|
|                               | <p><b>R2.2.2.</b> The Transmission Owner or Generator Owner shall repair or replace any Protection System or <b>RAS</b> that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the <b>RAS</b> if repair or replacement is not completed within 20 business days.</p> <p><b>R2.3.</b> If the Protection System or <b>RAS</b> has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or <b>RAS</b> that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following.</p> <p><b>R2.3.1.</b> When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.</p> <p><b>R2.3.2.</b> When FERAS is not available, then</p> <p><b>2.3.2.1.</b> The Generator Owners shall adjust generation to a reliable operating level, or</p> <p><b>2.3.2.2.</b> Transmission Operators shall adjust the SOL and operate the facilities within established limits.</p> <p><b>R2.4.</b> If the Protection System or <b>RAS</b> has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or <b>RAS</b> that failed, provided one of the following is performed.</p> <p><b>R2.4.1.</b> Transmission Owners or Generator Owners shall repair or replace any Protection System or <b>RAS</b> that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or</p> <p><b>R2.4.2.</b> Transmission Owners or Generator Owners shall remove from service the associated Element or <b>RAS</b>. [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Assessment</i>]</p> <p><b>R.3.</b> Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following.</p> <p><b>R3.1.</b> Identification of a Misoperation of a Protection System and/or <b>RAS</b>,</p> <p><b>R3.2.</b> Completion of repairs or the replacement of Protection System and/or <b>RAS</b> that misoperated.</p> |
| PRC-005-2                     | <p><b>4. Applicability:</b></p> <p><b>4.2.4</b> Protection Systems installed as a <b>Special Protection System (SPS)</b> for BES reliability.</p>  |
| PRC-005-2 Table 1-4(a) header | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-2 Table 1-4(b) header | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |

| Standard No.   | Existing Standard Language  |
|--|---|
| PRC-005-2 Table 1-4(c) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-2 Table 1-4(d) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-2 Table 1-4(e) header and Component Attributes                         | <p>Component Type - Protection System Station dc Supply for non-BES Interrupting Devices for <b>SPS</b>, non-distributed UFLS, and nondistributed UVLS systems</p> <p>Component Attributes: Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <b>SPS</b>, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).</p>   |
| PRC-005-2 Table 1-5 header and Component Attributes and Maintenance Activities | <p>Component Type - Control Circuitry Associated With Protective Functions</p> <p>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <b>SPSs</b> except as noted.</p> <p>Component Attributes: Unmonitored control circuitry associated with <b>SPS</b>.</p> <p>Maintenance Activities: Verify all paths of the control circuits essential for proper operation of the <b>SPS</b>.</p> <p>Component Attributes: Control circuitry associated with protective functions and/or <b>SPS</b> whose integrity is monitored and alarmed (See Table 2).</p> |
| PRC-005-3  | <p><b>4. Applicability:</b></p> <p><b>4.2.4</b> Protection Systems installed as a <b>Special Protection System (SPS)</b> for BES reliability.</p> <p><b>4.2.6.3</b> Automatic Reclosing applied as an integral part of an <b>SPS</b> specified in Section 4.2.4.</p>  |
| PRC-005-3 Table 1-4(a) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).   |
| PRC-005-3 Table 1-4(b) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).   |
| PRC-005-3 Table 1-4(c) header  | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-3 Table 1-4(d)   | Protection System Station dc supply used only for non-BES interrupting devices for <b>SPS</b> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |
| PRC-005-3 Table 1-4(e)   | <p>Component Type - Protection System Station dc Supply for non-BES Interrupting Devices for <b>SPS</b>, non-distributed UFLS, and non-distributed UVLS systems.</p> <p>Component Attributes: Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <b>SPS</b>, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).</p>   |
| PRC-005-3 Table 1-5 header and Component Attributes and                        | <p>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <b>SPSs</b> except as noted.</p> <p>Component Attributes: Unmonitored control circuitry associated with <b>SPS</b> (See Table 4-2(b) for <b>SPS</b> which include Automatic Reclosing.)</p>  |

| Standard No.  | Existing Standard Language   |
|---|--|
| <p><b>Maintenance Activities</b></p>  | <p>Maintenance Activities: Verify all paths of the control circuits essential for proper operation of the <b>SPS</b></p> <p>Component Attributes: Control circuitry associated with protective functions and/or <b>SPS</b> whose integrity is monitored and alarmed (See Table 2).</p>   |
| <p><b>PRC-005-3 Table 4-2(a) header and Component Attributes</b></p>                            | <p>Component Type - Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an <b>SPS</b></p> <p>Component Attributes: Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an <b>SPS</b></p> <p>Component Attributes: Control circuitry associated with Automatic Reclosing that is not part of an <b>SPS</b> and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)</p>  |
| <p><b>PRC-005-3 Table 4-2(b) header and Component Attributes and Maintenance Activities</b></p> | <p>Component Type - Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an <b>SPS</b></p> <p>Component Attributes: Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an <b>SPS</b> (regardless of any monitoring of the control circuitry).</p> <p>Component Attributes: Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an <b>SPS</b>.</p> <p>Maintenance Activities: Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the <b>SPS</b>.</p> <p>Component Attributes: Control circuitry associated with Automatic Reclosing that is an integral part of an <b>SPS</b> whose integrity is monitored and alarmed. (See Table 2)</p> |
| <p><b>PRC-006-1</b></p>   | <p><b>B. Requirements</b></p> <p><b>R. 2.2.</b> Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or <b>Special Protection System</b>, and</p> <p><b>E.B.</b> Regional Variance for the Western Electricity Coordinating Council</p> <p><b>E.B.2.2.</b> Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or <b>Special Protection System</b>.</p>   |
| <p><b>PRC-012-0</b></p>   | <p><b>A. Introduction</b></p> <p><b>1.</b> Title: <b>Special Protection System</b> Review Procedure</p> <p><b>3.</b> Purpose: To ensure that all <b>Special Protection Systems (SPS)</b> are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p>  |

| Standard No. | Existing Standard Language   |
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|              | <p><b>B. Requirements</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an <b>SPS</b> shall have a documented Regional Reliability Organization <b>SPS</b> review procedure to ensure that <b>SPSs</b> comply with Regional criteria and NERC Reliability Standards. The Regional <b>SPS</b> review procedure shall include:</p> <ul style="list-style-type: none"> <li><b>R1.1.</b> Description of the process for submitting a proposed <b>SPS</b> for Regional Reliability Organization review.</li> <li><b>R1.2.</b> Requirements to provide data that describes design, operation, and modeling of an <b>SPS</b>.</li> <li><b>R1.3.</b> Requirements to demonstrate that the <b>SPS</b> shall be designed so that a single <b>SPS</b> component failure, when the <b>SPS</b> was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</li> <li><b>R1.4.</b> Requirements to demonstrate that the inadvertent operation of an <b>SPS</b> shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.</li> <li><b>R1.5.</b> Requirements to demonstrate the proposed <b>SPS</b> will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.</li> <li><b>R1.7.</b> Requirements for analysis and documentation of corrective action plans for all <b>SPS</b> misoperations.</li> </ul> <p><b>R2.</b> The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its <b>SPS</b> review procedure on request (within 30 calendar days).</p> |

| Standard No.     | Existing Standard Language  |
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| <p>PRC-013-0</p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Special Protection System Database.</p> <p><b>3. Purpose:</b> To ensure that all Special Protection Systems (SPSs) are properly designed, meet performance requirements, and are coordinated with other protection systems.</p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:</p> <ul style="list-style-type: none"> <li><b>R1.1.</b> Design Objectives — Contingencies and system conditions for which the SPS was designed,</li> <li><b>R1.2.</b> Operation — The actions taken by the SPS in response to Disturbance conditions, and</li> <li><b>R1.3.</b> Modeling — Information on detection logic or relay settings that control operation of the SPS.</li> </ul>   |
| <p>PRC-014-0</p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Special Protection System Assessment</p> <p><b>3. Purpose:</b> To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria</p> <p><b>R2.</b> The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).</p> <p><b>R3.</b> The documentation of the Regional Reliability Organization’s SPS assessment shall include the following elements:</p> <ul style="list-style-type: none"> <li><b>R3.3.</b> Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.</li> <li><b>R3.4.</b> Discussion of any coordination problems found between a SPS and other protection and control systems.</li> <li><b>R3.5.</b> Provide corrective action plans for non-compliant SPSs.</li> </ul> |

| Standard No.     | Existing Standard Language   |
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| <p>PRC-015-0</p> | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> Special Protection System Data and Documentation</p> <p><b>3. Purpose:</b> To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>4. Applicability:</b></p> <p><b>4.1.</b> Transmission Owner that owns an SPS</p> <p><b>4.2.</b> Generator Owner that owns an SPS</p> <p><b>4.3.</b> Distribution Provider that owns an SPS</p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.</p> <p><b>R2.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.</p> <p><b>R3.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).</p> |

| Standard No.       | Existing Standard Language  |
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| <p>PRC-016-0.1</p> | <p><b>A. Introduction</b></p> <p>1. Title: <b>Special Protection System</b> Misoperations</p> <p>3. Purpose: To ensure that all <b>Special Protection Systems (SPS)</b> are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>4. Applicability:</b></p> <p>4.1. Transmission Owner that owns an <b>SPS</b></p> <p>4.2. Generator Owner that owns an <b>SPS</b></p> <p>4.3. Distribution Provider that owns an <b>SPS</b></p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall analyze its <b>SPS</b> operations and maintain a record of all misoperations in accordance with the Regional <b>SPS</b> review procedure specified in Reliability Standard PRC-012-0_R1.</p> <p><b>R2.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall take corrective actions to avoid future misoperations.</p> <p><b>R3.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).</p> |



| Standard No.                      | Existing Standard Language  |
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| <p>PRC-017-0</p>                  | <p><b>A. Introduction</b></p> <p><b>1. Title:</b> <b>Special Protection System</b> Maintenance and Testing</p> <p><b>3. Purpose:</b> To ensure that all <b>Special Protection Systems (SPS)</b> are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.</p> <p><b>4. Applicability:</b></p> <p><b>4.1.</b> Transmission Owner that owns an <b>SPS</b></p> <p><b>4.2.</b> Generator Owner that owns an <b>SPS</b></p> <p><b>4.3.</b> Distribution Provider that owns an <b>SPS</b></p> <p><b>B. Requirements</b></p> <p><b>R1.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall have a system maintenance and testing program(s) in place. The program(s) shall include:</p> <p style="padding-left: 40px;"><b>R1.1.</b> <b>SPS</b> identification shall include but is not limited to:</p> <p><b>R2.</b> The Transmission Owner, Generator Owner, and Distribution Provider that owns an <b>SPS</b> shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).</p> |
| <p>PRC-020-1</p>                  | <p><b>B. Requirements</b></p> <p><b>R1.6.</b> Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and <b>Special Protection Systems</b>.</p>  |
| <p>PRC-021-1</p>                  | <p><b>B. Requirements</b></p> <p><b>R1.5.</b> Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and <b>Special Protection Systems</b>.</p>  |
| <p>PRC-023-2<br/>Attachment A</p> | <p><b>2.</b> The following protection systems are excluded from requirements of this standard:</p> <p style="padding-left: 40px;"><b>2.5.</b> Relay elements used only for <b>Special Protection Systems</b> applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.</p>  |
| <p>PRC-023-3<br/>Attachment A</p> | <p><b>2.</b> The following protection systems are excluded from requirements of this standard:</p> <p style="padding-left: 40px;"><b>2.5.</b> Relay elements used only for <b>Special Protection Systems</b> applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.</p>  |
| <p>PRC-024-1</p>                  | <p><b>B. Requirements</b></p> <p><b>R2.</b> Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection<sup>2</sup>) caused by an event on the transmission system</p>  |

| Standard No.                          | Existing Standard Language   |
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|                                       | <p>external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions:</p> <ul style="list-style-type: none"> <li>• Generating unit(s) may trip in accordance with a <b>Special Protection System (SPS)</b> or <b>Remedial Action Scheme (RAS)</b>.</li> </ul>            |
| <p><b>PRC-025-1 Attachment 1</b></p>  | <p><b>Relay Settings:</b></p> <p><b>Exclusions:</b> The following protection systems are excluded from the requirements of this standard:</p> <p style="padding-left: 40px;">5. Protective relay elements used only for <b>Special Protection Systems</b> that are subject to one or more requirements in a NERC or Regional Reliability Standard.</p>   |
| <p><b>TOP-005-2a Attachment 1</b></p> | <p><b>Electric System Reliability Data</b></p> <p>This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.</p> <p style="padding-left: 40px;">2.6. New or degraded <b>Special Protection Systems</b>.</p>   |
| <p><b>TPL-001-0.1 Category D</b></p>  | <p><b>Table 1. Transmission System Standards - Normal and Emergency Conditions</b></p> <p style="padding-left: 40px;">12. Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p style="padding-left: 40px;">13. Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p>  |
| <p><b>TPL-001-4</b></p>               | <p><b>B. Requirements</b></p> <p style="padding-left: 40px;">2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:</p> <ul style="list-style-type: none"> <li>• Installation, modification, or removal of Protection Systems or <b>Special Protection Systems</b></li> </ul> <p style="padding-left: 40px;">4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a <b>Special Protection System</b> is not considered pulling out of synchronism.</p> |
| <p><b>TPL-002-0b Category D</b></p>   | <p><b>Table I. Transmission System Standards — Normal and Emergency Conditions</b></p> <p style="padding-left: 40px;">12. Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p style="padding-left: 40px;">13. Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p>  |

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| <p><b>TPL-003-0b</b><br/><b>Category D</b></p> | <p><b>Table I. Transmission System Standards — Normal and Emergency Conditions</b></p> <p>12. Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p> |
| <p><b>TPL-004-0a</b><br/><b>Category D</b></p> | <p><b>Table I. Transmission System Standards — Normal and Emergency Conditions</b></p> <p>12. Failure of a fully redundant <b>Special Protection System</b> (or <b>remedial action scheme</b>) to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant <b>Special Protection System</b> (or <b>Remedial Action Scheme</b>) in response to an event or abnormal system condition for which it was not intended to operate</p> |
| <p><b>WECC Regional Glossary Term:</b></p>     | <p><b>Definition: Dependability-Based Misoperation</b></p> <p>Is the absence of a Protection System or <b>RAS</b> operation when intended. Dependability is a component of reliability and is the measure of a device’s certainty to operate when required.</p>   |
| <p><b>WECC Regional Glossary Term:</b></p>     | <p><b>Definition: Functionally Equivalent RAS (FERAS)</b></p> <p>A <b>Remedial Action Scheme ("RAS")</b> that provides the same performance as follows:</p> <ul style="list-style-type: none"> <li>• Each <b>RAS</b> can detect the same conditions and provide mitigation to comply with all Reliability Standards.</li> <li>• Each <b>RAS</b> may have different components and operating characteristics</li> </ul>  |
| <p><b>WECC Regional Glossary Term:</b></p>     | <p><b>Definition: Security-Based Misoperation</b></p> <p>A Misoperation caused by the incorrect operation of a Protection System or <b>RAS</b>. Security is a component of reliability and is the measure of a device’s certainty not to operate falsely.</p>   |

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# “Remedial Action Scheme” Definition Development

## Background and Frequently Asked Questions

Project 2010-05.2 – Special Protection Systems

June 2014

**RELIABILITY | ACCOUNTABILITY**



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## Introduction

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The Project 2010-05.2 – Special Protection Systems Standard Drafting Team (SDT) thanks all commenters who submitted comments on the proposed revision to the NERC Glossary term “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) definition from the SAMS-SCPS SPS Technical Reference report. The revised definition was posted for a 30-day informal comment period from March 11, 2014 through April 9, 2014. NERC asked stakeholders to provide feedback on the proposed definition through a special electronic comment form.

The SDT appreciates the stakeholder comments on the revised definition. The SDT reviewed all of the comments and made numerous changes to the definition based on the feedback received. These changes are reflected in the first formal posting of the proposed revised definition for comment and ballot. The SDT developed this background and Frequently Asked Questions (FAQ) document to explain the key concepts incorporated in the revised definition, as well as the team’s approach and intent.

Contact the Standards Developer, Al McMeekin, at 404-446-9675 or at [al.mcmeekin@nerc.net](mailto:al.mcmeekin@nerc.net) with any comments or questions.

# Background – RAS Definition Development

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## Existing NERC Glossary of Terms Definitions

The existing NERC Glossary of Terms defines **SPS** or **RAS** as: “An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.”

The NERC Glossary of Terms defines a **Protection System** as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

## Revision of the NERC Glossary of Terms Definition

### Purpose of Revision of the NERC Glossary Terms SPS or RAS

The existing NERC Glossary of Terms definition for an SPS or RAS lacks the clarity and specificity necessary to consistently identify what equipment or schemes qualify as an SPS or RAS across the eight NERC Regions. This confusion leads to inconsistent application of the SPS or RAS-related NERC Reliability Standards.

The existing definition also lacks clarity in the actions stipulated as characteristics of an SPS or RAS. The actions listed in the definition are so broad that the definition may unintentionally include schemes whose purpose is not expressly related to preserving system reliability in response to predetermined system conditions. Inclusion of any scheme taking “corrective action other than isolation of faulted components to maintain system reliability” could be interpreted to mean that devices such as voltage regulators and switching controls for shunt capacitors should be included. This inclusion would then make these devices subject to requirements such as those addressing single-component failure considerations (sometimes referred to as redundancy considerations) in the SPS or RAS-related NERC Reliability Standards.

### Recommendation to Change the Term to RAS Only

Currently, both terms, SPS and RAS, are used in the eight NERC Regions. The SDT contends that a single term promotes consistency. The SDT therefore recommends that the term RAS be retained as the industry-recognized term and that the term SPS be retired. The term RAS is more descriptive of the purpose for which the scheme is installed.

The term RAS also eliminates the confusion associated with the two defined terms, “Special Protection System” and “Protection System.” The inclusion of Protection System in the term Special Protection System implies that SPS are a subset of Protection Systems. RAS are not Protection Systems; however, they may share components with Protection Systems.

### Effects of Using Only the Term RAS in the Existing NERC Reliability Standards

The existing NERC Reliability Standards and NERC Glossary of Terms use the terms, SPS and RAS interchangeably. In most cases, both terms are included in the standards and written as: “SPS or RAS.” The SDT evaluated the existing standards and recommended any necessary revisions to retain the single term, RAS. Many of the same changes would be required regardless of which single term is retained. A summary of the occurrences of the terms is included in the posted document *Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards*.

## Proposed Definition of RAS

**Remedial Action Scheme:** A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain System stability;
- Maintain acceptable System voltages;
- Maintain acceptable power flows;
- Limit the impact of Cascading; or
- Address other Bulk Electric System (BES) reliability concerns.

These schemes are not Protection Systems; however, they may share components with Protection Systems.

The following do not individually constitute a RAS:

- a. Out-of-step tripping and power swing blocking
- b. Automatic underfrequency load shedding (UFLS) programs
- c. Undervoltage Load Shedding Programs (UVLS Programs)
- d. Autoreclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, tap-changing transformers, or generation excitation, and that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by an operator



- l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

## Exclusion List Explanations

### a. Out-of-step tripping and power swing blocking

The existing NERC Glossary of Terms definition of SPS or RAS excludes out-of-step relaying because it is a protective function. The SDT maintained the exclusion but changed the wording from “out-of-step relaying” to “out-of-step tripping and power swing blocking” to reflect current industry terminology.

### b. Automatic underfrequency load shedding (UFLS) programs

The existing NERC Glossary of Terms definition of SPS or RAS excludes UFLS because it is a protective function that has unique design and implementation considerations that are covered by NERC Reliability Standard PRC-006-1. The SDT maintained the exclusion.

### c. Undervoltage Load Shedding Programs (UVLS Programs)

The existing NERC Glossary of Terms definition of SPS or RAS excludes undervoltage load shedding (UVLS) because it is a protective function. The SDT maintained the exclusion but is using the new term UVLS Program proposed by the SDT for NERC Project 2008-02 – Undervoltage Load Shedding. UVLS Programs are addressed in proposed NERC Reliability Standard PRC-010-1.

### d. Autoreclosing schemes

Autoreclosing schemes, whether single-pole or three-pole, are used to minimize system impacts and restoration efforts by System Operators. Autoreclosing, in itself, is not a RAS; however, if integrated into a larger scheme that performs additional corrective actions to accomplish the objective(s) listed in the RAS definition, then it would be part of a RAS. For example, a scheme that rejects or runs back generation to avoid instability or thermal overloads in addition to initiating autoreclosing would constitute a RAS.

### e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss of field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service

The SDT contends that these schemes are applied on an Element to protect it from damage. They are protective functions and are not RAS. The SDT accepts this exclusion consistent with industry practice.

### f. Controllers that switch or regulate series or shunt reactive devices, FACTS devices, phase-shifting transformers, variable-frequency transformers, tap-changing transformers, or generation excitation, and that are located at and monitor quantities solely at the same station as the Element being switched or regulated

The SDT contends these devices are not RAS. The SDT accepts this exclusion consistent with industry practice.

### g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

The SDT contends these devices are not RAS. The SDT accepts this exclusion consistent with industry practice.

### h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

Schemes or controllers that assist a System Operator in coordinating the switching of shunt reactors and shunt capacitors that would otherwise be manually switched are not remedial in the sense of being mitigations in response to predetermined System conditions, but are for general application to all System conditions.

**i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open**

When one end of a line is open, unacceptable voltage levels can occur. Opening the remote terminal(s) to de-energize the transmission line removes this voltage rise. These schemes have not historically been regarded as RAS, and the SDT accepts this exclusion consistent with industry practice.

**j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)**

These schemes are designed to protect load in an electrical island that might otherwise operate at an off-nominal frequency or voltage, or facilitate restoration. Actions taken on islanded facilities will not impact the interconnected BES because they are isolated. The SDT accepts this exclusion consistent with industry practice.

**k. Automatic sequences that proceed when manually initiated solely by an operator**

Automated sequences created to simplify the actions of an operator are not RAS because the decision to activate a specific sequence is left to the operator. If the automated sequence fails to execute correctly, the operator has the option to manually set those actions in motion. The SDT accepts this exclusion consistent with industry practice.

**l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations**

Modulation of HVdc and FACTS via supplementary controls is occasionally used for damping local or inter-area oscillations. They perform a similar function as a Power System Stabilizer (PSS), which is a component of excitation controls in a generating unit. PSS are not classified as RAS. The SDT accepts this exclusion consistent with industry practice.

**m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities; (e.g., currents or torsional oscillations)**

The SDT contends that directly detected SSR conditions and related mitigation are not RAS. The SDT accepts this exclusion consistent with industry practice.

## Explanations Regarding Changes from the Exclusion List Cited in the SAMS-SPCS Report

The SDT revised the straw man definition proposed in the SAMS-SPCS report; however, the proposed definition is consistent with the SAMS-SPCS intent. The drafting team revised the definition in response to stakeholder comments from the informal posting. As a result, it is no longer necessary to explicitly state some of the exclusions.

### 1. Schemes that prevent high line voltage by automatically switching the affected line

This scheme is now addressed by exceptions “e” (protection from high voltage) and “i” (automatic de-energization of a line when one end is open) in the proposed definition.

### 2. Protection schemes that operate local breakers other than those on the faulted circuit to facilitate Fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a Fault or to reduce fault duty

The scheme described in this exclusion is a Protection System. The proposed definition excludes Protection Systems from RAS.

### 3. Blanket exclusion for SSR protection schemes

The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

### 4. A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

The scheme described in this exclusion is a Protection System. The proposed definition excludes Protection Systems from RAS.

## Frequently Asked Questions

### Why does the proposed definition have an exclusion list?

The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS.

### Why did the SDT not propose a screening process to identify RAS?

The SDT contends that a comprehensive definition with specific exclusions is the best way to achieve consistency and immediacy in RAS identification. The SDT asserts that a study-based screening process would be labor-intensive and dependent on assumptions that could vary among the entities performing the studies.

### Why does the proposed definition not include the classification types suggested in the SPCS-SAMS report?

The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.

### Why did the SDT not specifically reference the Transmission Planning (TPL) standards in the proposed definition?

The SDT acknowledges that many RAS are installed to address the performance requirements of the TPL standards; however, they are also installed to address other reliability concerns.

**Would automatic actions taken by an Energy Management System (EMS), Supervisory Control and Data Acquisition (SCADA), or Distribution Control System (DCS) be considered a RAS?**

The above-mentioned control systems support and enable grid operations by issuing control commands mostly to geographically distributed power System devices. In this normal application, these systems are not considered to be RAS. However, if these systems are configured to detect predetermined conditions and take corrective actions consistent with the RAS definition, these automatic functions would be considered RAS. The identification of RAS is not dependent upon the specific hardware or platform utilized in the scheme.

**What are the Implementation Plan time frames?**

The Implementation Plan provides RAS owners a minimum of twelve (12) months beyond the date of approval by a governmental authority to evaluate their current schemes for determining whether they are RAS, based on the new definition. The drafting team contends that twelve (12) months is an adequate period of time to review existing schemes to determine whether they are RAS.

The Implementation Plan also provides owners of newly identified RAS twenty-four (24) calendar months beyond the date of approval by a governmental authority to be fully compliant with all standards applicable to the revised definition of Remedial Action Scheme. The drafting team contends that twenty-four (24) calendar months provides the RAS owner sufficient time to become compliant with the revised standards proposed in the Implementation Plan.

**Coordination with Project 2008-02 – Undervoltage Load Shedding**

As part of the current development of PRC-010-1, the Project 2008-02 UVLS SDT is introducing a new NERC Glossary term, UVLS Program, to clearly establish applicability of PRC-010-1:

**Undervoltage Load Shedding Program (UVLS Program):** An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.

Note that the definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, centrally controlled undervoltage-based load shedding should be subject to RAS-related Reliability Standards.

The Project 2010-05.2 SPS SDT agrees with the Project 2008-02 UVLS SDT that the design and characteristics of centrally controlled undervoltage-based load shedding are more appropriately categorized as RAS. The SPS SDT has therefore revised the definition of RAS to clarify that the definition is exclusive of only the newly defined term UVLS Program, and is therefore inclusive of centrally controlled undervoltage-based load shedding. The SDT is coordinating this change with the Project 2008-02 UVLS SDT. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as a RAS. As a result, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective date of the revised definition of RAS.

## Attachment A – SDT Members

| Project 2010-05.2 – Special Protection Systems SDT |                                     |                                       |
|--|-------------------------------------|---------------------------------------|
|  | Participant                         | Entity                                |
| Chair  | Gene Henneberg                      | NV Energy / Berkshire Hathaway Energy |
| Vice Chair   | Bobby Jones                         | Southern Company                      |
| Member   | Amos Ang                            | Southern California Edison            |
|  | John Ciufo                          | Hydro One Inc.                        |
|  | Alan Engelmann                      | ComEd / Exelon                        |
|  | Davis Erwin                         | Pacific Gas and Electric              |
|  | Sharma Kolluri                      | Entergy                               |
|  | Charles-Eric Langlois               | Hydro-Quebec TransEnergie             |
|  | Robert J. O'Keefe                   | American Electric Power               |
|  | Hari Singh                          | Xcel Energy                           |
| NERC Staff   | Al McMeekin (Standards Developer)   | NERC                                  |
|  | Erika Chanzas (Standards Developer) | NERC                                  |
|  | Phil Tatro (Technical Advisor)      | NERC                                  |
|  | Bill Edwards (Legal Counsel)        | NERC                                  |

# Project 2008-02 Undervoltage Load Shedding

Coordination Plan | June 11, 2014

## Background

Project 2008-02 Undervoltage Load Shedding (“UVLS Project”) proposes to consolidate and retire PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1 to create PRC-010-1 – Undervoltage Load Shedding. During development, the drafting team identified the following necessary corresponding changes to meet the design of PRC-010-1:

- 1) Retire three requirements in EOP-003-2 – Load Shedding Plans whose required performance is reflected in proposed PRC-010-1.
- 2) Revise the NERC Glossary definition of the term Special Protection System (SPS) to clarify that centrally controlled undervoltage-based load shedding is an SPS because of its design and characteristics.
- 3) Modify PRC-004-3 – Protection System Misoperation Identification and Correction, which excludes UVLS, to include certain types of UVLS programs as part of its applicable facilities.

To make these changes, the UVLS drafting team is coordinating with drafting teams from the three active NERC standard development projects listed below:

- Project 2009-03 – Emergency Operations (“EOP Project”)
- Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) (“SPS Project”)
- Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems) (“Misoperations Project”)

### **Current Coordination Plan**

NERC has developed a preferred coordination plan for the above-mentioned projects that will properly align the development and implementation of the revised standards and definitions with the retirements of the legacy standards.

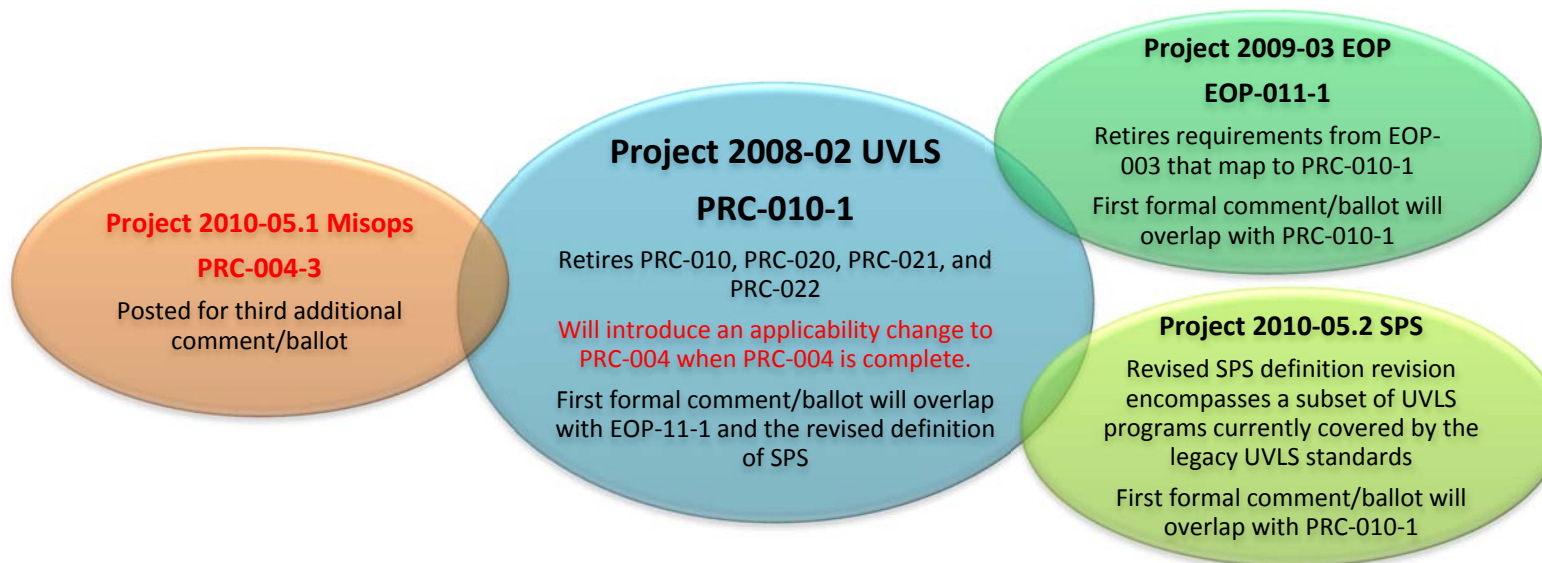
- 1) The EOP and UVLS Projects will progress simultaneously and coordinate necessary changes. Comment periods and ballots for each project will run concurrently or overlap.
- 2) The UVLS Project will progress simultaneously with the SPS definition revision by the SPS Project to assure the cohesive transfer of certain aspects of the legacy UVLS standards to the SPS standards. Comment periods and ballots for each project will run concurrently or overlap.
- 3) The UVLS Project will address the conforming changes needed to PRC-004 after PRC-004-3 is complete. How and when this will occur depends on when PRC-004-3 obtains approval from the ballot body and is adopted by the NERC Board of Trustees.

An illustrative diagram of this coordination appears on the next page. This plan is subject to change as necessary.

### **General Considerations**

The revised definition of SPS, the UVLS Project, and the EOP Project should be presented simultaneously to industry, the NERC Board of Trustees, and applicable regulatory authorities. The associated effective dates and retirements for these projects need to align to accommodate the needed transitions of standard coverage.

The implementation plan for the revised SPS definition will provide entities time to address any newly-identified SPS resulting from the application of the revised definition of SPS which will include centrally controlled undervoltage-based load shedding.



**April 2014**  
First SPS SDT Meeting

**February 2015**  
UVLS and EOP Standards and SPS Definition to BOT

**TBD**  
Revised SPS Standards to BOT

**June 2014**  
UVLS and EOP Standards and SPS Definition First Ballot

**April 2015**  
UVLS and EOP Standards and SPS Definition Petition Package to FERC



# Standards Announcement

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Special Protection System

Ballot Now Open through July 25, 2014

### [Now Available](#)

A ballot for the **Revised Definition of Special Protection System/Remedial Action Scheme** is open through **8 p.m. Eastern on Friday, July 25, 2014.**

Background information for this project can be found on the [project page](#).

### **Instructions for Balloting**

Members of the ballot pools associated with this project may log in and submit their vote for the definition by clicking [here](#).

### **Next Steps**

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Wendy Muller](#),  
Standards Development Administrator, or at 404-446-2560.*

North American Electric Reliability Corporation

3353 Peachtree Rd, NE

Suite 600, North Tower

Atlanta, GA 30326

404-446-2560 | [www.nerc.com](http://www.nerc.com)

# Standards Announcement

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Special Protection System

**Formal Comment Period Now Open through July 25, 2014**  
**Ballot Pool Forming Now through July 10, 2014**

### [Now Available](#)

A 45-day formal comment period for the **Revised Definition of Special Protection System/Remedial Action Scheme** is open through **8 p.m. Eastern on Friday, July 25, 2014.**

If you have questions please contact [Al McMeekin](#) via email or by telephone at (803) 530-1963.

Background information for this project can be found on the [project page](#).

### **Instructions for Commenting**

Please use the [electronic form](#) to submit comments on the revised definition. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

### **Instructions for Joining Ballot Pool**

A ballot pool is currently being formed. Registered Ballot Body members must join the ballot pool to be eligible to cast a ballot. Registered Ballot Body members may join the ballot pool at the following page: [Join Ballot Pool](#)

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The list server for this project is:

[bp-Def of RAS 062014 in@nerc.com](mailto:bp-Def_of_RAS_062014_in@nerc.com)

### **Next Steps**

A ballot for the definition will be conducted **July 16-25, 2014.**

For information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Wendy Muller](#),  
Standards Development Administrator, or at 404-446-2560.*

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# Standards Announcement

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Special Protection System

### Ballot Results

#### [Now Available](#)

A ballot of **Revised Definition of Special Protection System/Remedial Action Scheme** concluded at **8 p.m. Eastern on Friday, July 25, 2014.**

The definition achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

| Ballot           |
|------------------|
| Quorum /Approval |
| 78.92% / 58.88%  |

Background information for this project can be found on the [project page](#).

### Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition and post it for an additional ballot. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Wendy Muller](#),  
Standards Development Administrator, or at 404-446-2560.*

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- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters
- Register

[Home Page](#)

| Ballot Results                |  |
|-------------------------------|--|
| <b>Ballot Name:</b>           | Definition_of_Remedial_Action_Scheme       |
| <b>Ballot Period:</b>         | 7/16/2014 - 7/25/2014                      |
| <b>Ballot Type:</b>           | Initial                                    |
| <b>Total # Votes:</b>         | 292  |
| <b>Total Ballot Pool:</b>     | 370  |
| <b>Quorum:</b>                | <b>78.92 % The Quorum has been reached</b> |
| <b>Weighted Segment Vote:</b> | 58.88 %                                    |
| <b>Ballot Results:</b>        | <b>The ballot has closed</b>               |

| Summary of Ballot Results |             |                |             |          |          |          |                                 |         |         |  |
|---------------------------|-------------|----------------|-------------|----------|----------|----------|---------------------------------|---------|---------|--|
| Segment                   | Ballot Pool | Segment Weight | Affirmative |          | Negative |          | Negative Vote without a Comment | Abstain | No Vote |  |
|                           |             |                | # Votes     | Fraction | # Votes  | Fraction |                                 |         |         |  |
| 1 - Segment 1             | 101         | 1              | 40          | 0.563    | 31       | 0.437    | 0                               | 8       | 22      |  |
| 2 - Segment 2             | 9           | 0.7            | 5           | 0.5      | 2        | 0.2      | 0                               | 0       | 2       |  |
| 3 - Segment 3             | 84          | 1              | 31          | 0.484    | 33       | 0.516    | 2                               | 4       | 14      |  |
| 4 - Segment 4             | 27          | 1              | 11          | 0.55     | 9        | 0.45     | 0                               | 3       | 4       |  |
| 5 - Segment 5             | 79          | 1              | 22          | 0.489    | 23       | 0.511    | 2                               | 9       | 23      |  |
| 6 - Segment 6             | 53          | 1              | 20          | 0.5      | 20       | 0.5      | 0                               | 7       | 6       |  |
| 7 - Segment 7             | 3           | 0              | 0           | 0        | 0        | 0        | 0                               | 0       | 3       |  |
| 8 - Segment 8             | 4           | 0.2            | 2           | 0.2      | 0        | 0        | 0                               | 0       | 2       |  |
| 9 - Segment 9             | 3           | 0.1            | 0           | 0        | 1        | 0.1      | 0                               | 1       | 1       |  |

|                 |            |            |            |              |            |              |          |           |           |
|-----------------|------------|------------|------------|--------------|------------|--------------|----------|-----------|-----------|
| 10 - Segment 10 | 7          | 0.6        | 6          | 0.6          | 0          | 0            | 0        | 0         | 1         |
| <b>Totals</b>   | <b>370</b> | <b>6.6</b> | <b>137</b> | <b>3.886</b> | <b>119</b> | <b>2.714</b> | <b>4</b> | <b>32</b> | <b>78</b> |

| Individual Ballot Pool Results |  |                              |             |  |
|--------------------------------|--|------------------------------|-------------|--|
| Segment                        | Organization                               | Member                       | Ballot      | NERC Notes   |
| 1                              | Ameren Services                            | Eric Scott                   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Ameren)                     |
| 1                              | American Electric Power                    | Paul B Johnson               | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)            |
| 1                              | American Transmission Company, LLC         | Andrew Z Pusztai             | Affirmative |  |
| 1                              | Arizona Public Service Co.                 | Brian Cole                   | Affirmative |  |
| 1                              | Associated Electric Cooperative, Inc.      | John Bussman                 | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                       |
| 1                              | Austin Energy                              | James Armke                  | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney-FMPA)         |
| 1                              | Avista Utilities                           | Heather Rosentrater          |             |  |
| 1                              | Balancing Authority of Northern California | Kevin Smith                  | Affirmative |  |
| 1                              | Baltimore Gas & Electric Company           | Christopher J Scanlon        | Affirmative |  |
| 1                              | Basin Electric Power Cooperative           | David Rudolph                |             |  |
| 1                              | BC Hydro and Power Authority               | Patricia Robertson           | Affirmative |  |
| 1                              | Black Hills Corp                           | Wes Wingen                   | Affirmative |  |
| 1                              | Bonneville Power Administration            | Donald S. Watkins            | Affirmative |  |
| 1                              | Bryan Texas Utilities                      | John C Fontenot              | Affirmative |  |
| 1                              | CenterPoint Energy Houston Electric, LLC   | John Brockhan                | Affirmative |  |
| 1                              | Central Electric Power Cooperative         | Michael B Bax                |             |  |
| 1                              | Central Iowa Power Cooperative             | Kevin J Lyons                | Negative    | SUPPORTS THIRD PARTY COMMENTS - (ACES)                       |
| 1                              | City of Tallahassee                        | Daniel S Langston            | Abstain     |  |
| 1                              | Clark Public Utilities                     | Jack Stamper                 | Affirmative |  |
| 1                              | Colorado Springs Utilities                 | Shawna Speer                 | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities) |
| 1                              | Consolidated Edison Co. of New York        | Christopher L de Graffenried | Affirmative |  |
| 1                              | Dairyland Power Coop.                      | Robert W. Roddy              | Affirmative |  |
| 1                              | Dayton Power & Light Co.                   | Hertzel Shamash              |             |  |
| 1                              | Deseret Power                              | James Tucker                 |             |  |
| 1                              | Dominion Virginia Power                    | Larry Nash                   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Dominion's)                 |
| 1                              | Duke Energy Carolina                       | Doug E Hils                  | Affirmative |  |
| 1                              | Entergy Transmission                       | Oliver A Burke               | Affirmative |  |
| 1                              | FirstEnergy Corp.                          | William J Smith              | Affirmative |  |
| 1                              | Florida Keys Electric Cooperative Assoc.   | Dennis Minton                | Affirmative |  |
| 1                              | Florida Power & Light Co.                  | Mike O'Neil                  | Affirmative |  |
| 1                              | Gainesville Regional Utilities             | Richard Bachmeier            |             |  |
| 1                              | Georgia Transmission Corporation           | Jason Snodgrass              | Affirmative |  |
| 1                              | Great River Energy                         | Gordon Pietsch               | Affirmative |  |
| 1                              | Hydro One Networks, Inc.                   | Muhammed Ali                 | Negative    | COMMENT RECEIVED   |
| 1                              | Hydro-Quebec TransEnergie                  | Martin Boisvert              | Affirmative |  |



|   |  |                         |             |   |
|---|--|-------------------------|-------------|---|
| 1 | Idaho Power Company                              | Molly Devine            | Affirmative |   |
| 1 | International Transmission Company Holdings Corp | Michael Moltane         | Abstain     |   |
| 1 | JDRJC Associates                                 | Jim D Cyrulewski        |             |   |
| 1 | JEA  | Ted E Hobson            |             |   |
| 1 | KAMO Electric Cooperative                        | Walter Kenyon           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)  |
| 1 | Kansas City Power & Light Co.                    | Daniel Gibson           | Affirmative |   |
| 1 | Lakeland Electric                                | Larry E Watt            | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))             |
| 1 | Lincoln Electric System                          | Doug Bantam             | Abstain     |   |
| 1 | Long Island Power Authority                      | Robert Ganley           |             |   |
| 1 | Lower Colorado River Authority                   | Martyn Turner           | Negative    | COMMENT RECEIVED  |
| 1 | M & A Electric Power Cooperative                 | William Price           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)  |
| 1 | Manitoba Hydro                                   | Jo-Anne M Ross          | Negative    | COMMENT RECEIVED  |
| 1 | MEAG Power                                       | Danny Dees              | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA)  |
| 1 | MidAmerican Energy Co.                           | Terry Harbour           |             |   |
| 1 | Minnkota Power Coop. Inc.                        | Daniel L Inman          | Affirmative |   |
| 1 | Muscatine Power & Water                          | Andrew J Kurriger       |             |   |
| 1 | N.W. Electric Power Cooperative, Inc.            | Mark Ramsey             | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)  |
| 1 | National Grid USA                                | Michael Jones           | Negative    | COMMENT RECEIVED  |
| 1 | NB Power Corporation                             | Alan MacNaughton        | Abstain     |   |
| 1 | Nebraska Public Power District                   | Jamison Cawley          | Negative    | COMMENT RECEIVED  |
| 1 | New York Power Authority                         | Bruce Metruck           | Affirmative |   |
| 1 | Northeast Missouri Electric Power Cooperative    | Kevin White             | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)  |
| 1 | Northeast Utilities                              | William Temple          | Affirmative |   |
| 1 | Northern Indiana Public Service Co.              | Julaine Dyke            | Abstain     |   |
| 1 | Ohio Valley Electric Corp.                       | Scott R Cunningham      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz (American Electric Power))            |
| 1 | Oklahoma Gas and Electric Co.                    | Terri Pyle              | Affirmative |   |
| 1 | Omaha Public Power District                      | Doug Peterchuck         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Supporting Mahmood Safi's comments (OPD Comments)) |
| 1 | Oncor Electric Delivery                          | Jen Fiegel              | Negative    | COMMENT RECEIVED  |
| 1 | Orlando Utilities Commission                     | Brad Chase              |             |   |
| 1 | Otter Tail Power Company                         | Daryl Hanson            |             |   |
| 1 | Pacific Gas and Electric Company                 | Bangalore Vijayraghavan |             |   |
| 1 | Peak Reliability                                 | Jared Shakespeare       | Affirmative |   |
|   |  |                         |             | SUPPORTS THIRD PARTY  |

|   |   |                               |             |   |
|---|---|-------------------------------|-------------|---|
| 1 | Platte River Power Authority                          | John C. Collins               | Negative    | COMMENTS - (Colorado Springs Utilities)                                     |
| 1 | Portland General Electric Co.                         | John T Walker                 | Affirmative |   |
| 1 | Potomac Electric Power Co.                            | David Thorne                  | Affirmative |   |
| 1 | PPL Electric Utilities Corp.                          | Brenda L Truhe                | Abstain     |   |
| 1 | Public Service Company of New Mexico                  | Laurie Williams               | Affirmative |   |
| 1 | Public Service Electric and Gas Co.                   | Kenneth D. Brown              | Affirmative |   |
| 1 | Public Utility District No. 1 of Okanogan County      | Dale Dunckel                  |             |   |
| 1 | Puget Sound Energy, Inc.                              | Denise M Lietz                | Affirmative |   |
| 1 | Rochester Gas and Electric Corp.                      | John C. Allen                 | Affirmative |   |
| 1 | Sacramento Municipal Utility District                 | Tim Kelley                    | Affirmative |   |
| 1 | Salt River Project                                    | Robert Kondziolka             | Affirmative |   |
| 1 | San Diego Gas & Electric                              | Will Speer                    |             |   |
| 1 | SaskPower   | Wayne Guttormson              |             |   |
| 1 | Seattle City Light                                    | Pawel Krupa                   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Haase's comment) |
| 1 | Seminole Electric Cooperative, Inc.                   | Glenn Spurlock                |             |   |
| 1 | Sho-Me Power Electric Cooperative                     | Denise Stevens                |             |   |
| 1 | Snohomish County PUD No. 1                            | Long T Duong                  | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA)                                      |
| 1 | South Carolina Electric & Gas Co.                     | Tom Hanzlik                   | Affirmative |   |
| 1 | South Carolina Public Service Authority               | Shawn T Abrams                | Abstain     |   |
| 1 | Southern California Edison Company                    | Steven Mavis                  | Affirmative |   |
| 1 | Southern Company Services, Inc.                       | Robert A. Schaffeld           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Southern Company)                          |
| 1 | Southern Illinois Power Coop.                         | William Hutchison             |             |   |
| 1 | Southwest Transmission Cooperative, Inc.              | John Shaver                   | Affirmative |   |
| 1 | Sunflower Electric Power Corporation                  | Noman Lee Williams            | Negative    | SUPPORTS THIRD PARTY COMMENTS - (ACES)                                      |
| 1 | Tacoma Power  | John Merrell                  | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)                              |
| 1 | Tennessee Valley Authority                            | Howell D Scott                | Negative    | COMMENT RECEIVED  |
| 1 | Tri-State Generation & Transmission Association, Inc. | Tracy Sliman                  | Negative    | COMMENT RECEIVED  |
| 1 | Tucson Electric Power Co.                             | John Tolo                     |             |   |
| 1 | U.S. Bureau of Reclamation                            | Richard T Jackson             | Abstain     |   |
| 1 | United Illuminating Co.                               | Jonathan Appelbaum            | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NPCC)                                      |
| 1 | Westar Energy   | Allen Klassen                 | Affirmative |   |
| 1 | Western Area Power Administration                     | Lloyd A Linke                 |             |   |
| 1 | Wolverine Power Supply Coop., Inc.                    | Michelle Clements             | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NRECA)                                     |
| 1 | Xcel Energy, Inc.                                     | Gregory L Pieper              | Affirmative |   |
| 2 | BC Hydro  | Venkataramakrishnan Vinnakota |             |   |
| 2 | California ISO  | Rich Vine                     | Affirmative |   |
| 2 | Electric Reliability Council of Texas, Inc.           | Cheryl Moseley                | Negative    | SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)                                   |
| 2 | Independent Electricity System Operator               | Leonard Kula                  | Affirmative |   |
| 2 | ISO New England, Inc.                                 | Matthew F Goldberg            | Affirmative |   |

|   |                                       |                     |             |  |
|---|---------------------------------------|---------------------|-------------|--|
| 2 | MISO                                  | Marie Knox          | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(ISO/RTO<br>SRC)  |
| 2 | New York Independent System Operator  | Gregory Campoli     |             |  |
| 2 | PJM Interconnection, L.L.C.           | stephanie monzon    | Affirmative |  |
| 2 | Southwest Power Pool, Inc.            | Charles H. Yeung    | Affirmative |  |
| 3 | AEP                                   | Michael E Deloach   | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(Thomas Foltz<br>- American<br>Electric Power<br>(AEP)) |
| 3 | Alabama Power Company                 | Robert S Moore      | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(Southern<br>Company)                                   |
| 3 | Ameren Corp.                          | David J Jendras     | Affirmative |  |
| 3 | APS                                   | Sarah Kist          | Affirmative |  |
| 3 | Associated Electric Cooperative, Inc. | Todd Bennett        | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(AECI)  |
| 3 | Atlantic City Electric Company        | NICOLE BUCKMAN      | Affirmative |  |
| 3 | Avista Corp.                          | Scott J Kinney      | Affirmative |  |
| 3 | BC Hydro and Power Authority          | Pat G. Harrington   | Affirmative |  |
| 3 | Bonneville Power Administration       | Rebecca Berdahl     | Affirmative |  |
| 3 | Central Electric Power Cooperative    | Adam M Weber        | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(AECI)  |
| 3 | Central Lincoln PUD                   | Steve Alexanderson  | Negative    | COMMENT<br>RECEIVED  |
| 3 | City of Austin dba Austin Energy      | Andrew Gallo        |             |  |
| 3 | City of Clewiston                     | Lynne Mila          | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(FMPA)  |
| 3 | City of Farmington                    | Linda R Jacobson    |             |  |
| 3 | City of Garland                       | Ronnie C Hoeinghaus |             |  |
| 3 | City of Green Cove Springs            | Mark Schultz        | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(FMPA)  |
| 3 | City of Redding                       | Bill Hughes         | Affirmative |  |
| 3 | City of Tallahassee                   | Bill R Fowler       | Abstain     |  |
| 3 | City of Vineland                      | Kathy Caignon       | Negative    | COMMENT<br>RECEIVED  |
| 3 | Cleco Corporation                     | Michelle A Corley   | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(See SPP<br>Comments)                                   |
| 3 | Colorado Springs Utilities            | Jean Mueller        |             |  |
| 3 | ComEd                                 | John Bee            | Affirmative |  |
| 3 | Consolidated Edison Co. of New York   | Peter T Yost        | Affirmative |  |
| 3 | Consumers Energy Company              | Gerald G Farringer  | Negative    | COMMENT<br>RECEIVED  |
| 3 | Cowlitz County PUD                    | Russell A Noble     | Affirmative |  |
| 3 | CPS Energy                            | Jose Escamilla      |             |  |
| 3 | Delmarva Power & Light Co.            | Michael R. Mayer    | Affirmative |  |
| 3 | Dominion Resources, Inc.              | Connie B Lowe       | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(See<br>Dominion's<br>submitted<br>comments)            |
| 3 | DTE Electric                          | Kent Kujala         | Abstain     |  |
| 3 | FirstEnergy Corp.                     | Cindy E Stewart     | Affirmative |  |
| 3 | Florida Keys Electric Cooperative     | Tom B Anthony       | Affirmative |  |

|   |   |                     |             |   |
|---|---|---------------------|-------------|---|
| 3 | Florida Municipal Power Agency                | Joe McKinney        | Negative    | COMMENT RECEIVED  |
| 3 | Florida Power Corporation                     | Lee Schuster        | Affirmative |   |
| 3 | Gainesville Regional Utilities                | Kenneth Simmons     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMFA)                                |
| 3 | Great River Energy                            | Brian Glover        | Affirmative |   |
| 3 | Hydro One Networks, Inc.                      | Ayesha Sabouba      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Muhammed Ali)                        |
| 3 | Imperial Irrigation District                  | Jesus S. Alcaraz    |             |   |
| 3 | JEA   | Garry Baker         |             |   |
| 3 | KAMO Electric Cooperative                     | Theodore J Hilmes   |             |   |
| 3 | Kansas City Power & Light Co.                 | Joshua D Bach       | Affirmative |   |
| 3 | Kissimmee Utility Authority                   | Gregory D Woessner  | Affirmative |   |
| 3 | Lakeland Electric                             | Mace D Hunter       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMFA)                                |
| 3 | Lincoln Electric System                       | Jason Fortik        | Abstain     |   |
| 3 | Los Angeles Department of Water & Power       | Mike Anctil         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMFA) - (LADWP)                      |
| 3 | Louisville Gas and Electric Co.               | Charles A. Freibert |             |   |
| 3 | M & A Electric Power Cooperative              | Stephen D Pogue     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                |
| 3 | Manitoba Hydro                                | Greg C. Parent      | Negative    | COMMENT RECEIVED  |
| 3 | MEAG Power                                    | Roger Brand         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMFA)                                |
| 3 | MidAmerican Energy Co.                        | Thomas C. Mielnik   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Comments Submitted by the MRO NSRF.) |
| 3 | Modesto Irrigation District                   | Jack W Savage       | Affirmative |   |
| 3 | National Grid USA                             | Brian E Shanahan    | Negative    | SUPPORTS THIRD PARTY COMMENTS - (National Grid - Michael Jones)       |
| 3 | Nebraska Public Power District                | Tony Eddleman       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (I support NPPD and SPP comments)     |
| 3 | New York Power Authority                      | David R Rivera      | Affirmative |   |
| 3 | Northeast Missouri Electric Power Cooperative | Skyler Wiegmann     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                |
| 3 | Northern Indiana Public Service Co.           | Ramon J Barany      | Negative    | NO COMMENT RECEIVED - (Joe O'Brien on behalf of Jerry Freese)         |
| 3 | NW Electric Power Cooperative, Inc.           | David McDowell      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                |
| 3 | Ocala Utility Services                        | Randy Hahn          | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMFA)                                |

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|---|---|---------------------|-------------|---|
| 3 | Oklahoma Gas and Electric Co.                         | Donald Hargrove     | Affirmative |   |
| 3 | Omaha Public Power District                           | Blaine R. Dinwiddie |             |   |
| 3 | Orlando Utilities Commission                          | Ballard K Mutters   | Affirmative |   |
| 3 | Owensboro Municipal Utilities                         | Thomas T Lyons      |             |   |
| 3 | Pacific Gas and Electric Company                      | John H Hagen        |             |   |
| 3 | Platte River Power Authority                          | Terry L Baker       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (CSU)                                       |
| 3 | PNM Resources   | Michael Mertz       |             |   |
| 3 | Portland General Electric Co.                         | Thomas G Ward       | Affirmative |   |
| 3 | Potomac Electric Power Co.                            | Mark Yerger         | Affirmative |   |
| 3 | Public Service Electric and Gas Co.                   | Jeffrey Mueller     | Affirmative |   |
| 3 | Puget Sound Energy, Inc.                              | Mariah R Kennedy    | Affirmative |   |
| 3 | Sacramento Municipal Utility District                 | James Leigh-Kendall | Affirmative |   |
| 3 | Salt River Project                                    | John T. Underhill   | Affirmative |   |
| 3 | Santee Cooper   | James M Poston      | Abstain     |   |
| 3 | Seattle City Light                                    | Dana Wheelock       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Haase's comment) |
| 3 | Seminole Electric Cooperative, Inc.                   | James R Frauen      | Negative    | NO COMMENT RECEIVED - (Seminole Electric Cooperative)                       |
| 3 | Sho-Me Power Electric Cooperative                     | Jeff L Neas         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                      |
| 3 | Snohomish County PUD No. 1                            | Mark Oens           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMFA)                                      |
| 3 | South Carolina Electric & Gas Co.                     | Hubert C Young      | Affirmative |   |
| 3 | Southern California Edison Company                    | Lujuanna Medina     | Affirmative |   |
| 3 | Tacoma Power  | Marc Donaldson      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)                              |
| 3 | Tampa Electric Co.                                    | Ronald L. Donahey   |             |   |
| 3 | Tennessee Valley Authority                            | Ian S Grant         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (TVA)                                       |
| 3 | Tri-State Generation & Transmission Association, Inc. | Janelle Marriott    | Negative    | COMMENT RECEIVED  |
| 3 | Westar Energy   | Bo Jones            | Affirmative |   |
| 3 | Wisconsin Electric Power Marketing                    | James R Keller      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)                            |
| 3 | Xcel Energy, Inc.                                     | Michael Ibold       | Affirmative |   |
| 4 | Alliant Energy Corp. Services, Inc.                   | Kenneth Goldsmith   | Affirmative |   |
| 4 | Blue Ridge Power Agency                               | Duane S Dahlquist   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Support the comments of FMFA)              |
| 4 | Central Lincoln PUD                                   | Shamus J Gamache    | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson, Central Lincoln)       |
| 4 | City of Austin dba Austin Energy                      | Reza Ebrahimian     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Frank                                      |

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|---|---|---------------------|-------------|---|
|   |   |                     |             | Gaffney)  |
| 4 | City of Redding   | Nicholas Zettel     | Affirmative |   |
| 4 | City Utilities of Springfield, Missouri                           | John Allen          |             |   |
| 4 | Constellation Energy Control & Dispatch, L.L.C.                   | Margaret Powell     |             |   |
| 4 | Consumers Energy Company  | Tracy Goble         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Richard Pienkos)                           |
| 4 | Cowlitz County PUD  | Rick Syring         | Affirmative |   |
| 4 | DTE Electric  | Daniel Herring      | Abstain     |   |
| 4 | Florida Municipal Power Agency                                    | Carol Chinn         | Negative    | COMMENT RECEIVED  |
| 4 | Georgia System Operations Corporation                             | Guy Andrews         | Affirmative |   |
| 4 | Herb Schrayshuen  | Herb Schrayshuen    | Affirmative |   |
| 4 | Illinois Municipal Electric Agency                                | Bob C. Thomas       | Abstain     |   |
| 4 | Indiana Municipal Power Agency                                    | Jack Alvey          |             |   |
| 4 | Integrus Energy Group, Inc.                                       | Christopher Plante  |             |   |
| 4 | Madison Gas and Electric Co.                                      | Joseph DePoorter    | Affirmative |   |
| 4 | Modesto Irrigation District                                       | Spencer Tacke       | Affirmative |   |
| 4 | Ohio Edison Company   | Douglas Hohlbauh    | Affirmative |   |
| 4 | Public Utility District No. 1 of Snohomish County                 | John D Martinsen    | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA)                                      |
| 4 | Sacramento Municipal Utility District                             | Mike Ramirez        | Affirmative |   |
| 4 | Seattle City Light  | Hao Li              | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Haase's comment) |
| 4 | Seminole Electric Cooperative, Inc.                               | Steven R Wallace    | Abstain     |   |
| 4 | South Mississippi Electric Power Association                      | Steve McElhaney     | Affirmative |   |
| 4 | Tacoma Public Utilities   | Keith Morisette     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Mike Hill)                                 |
| 4 | Utility Services, Inc.  | Brian Evans-Mongeon | Affirmative |   |
| 4 | Wisconsin Energy Corp.  | Anthony P Jankowski | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Barb Kederowski of We Energies)            |
| 5 | Amerenue  | Sam Dwyer           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)                         |
| 5 | American Electric Power   | Thomas Foltz        | Negative    | COMMENT RECEIVED  |
| 5 | Arizona Public Service Co.  | Scott Takinen       | Affirmative |   |
| 5 | Associated Electric Cooperative, Inc.                             | Matthew Pacobit     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                      |
| 5 | BC Hydro and Power Authority                                      | Clement Ma          |             |   |
| 5 | Boise-Kuna Irrigation District/dba Lucky peak power plant project | Mike D Kukla        |             |   |
| 5 | Bonneville Power Administration                                   | Francis J. Halpin   | Affirmative |   |
| 5 | Brazos Electric Power Cooperative, Inc.                           | Shari Heino         |             |   |
| 5 | Calpine Corporation   | Hamid Zakery        |             |   |
| 5 | City of Austin dba Austin Energy                                  | Jeanie Doty         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Carol Chinn of FMPA)                       |
| 5 | City of Redding   | Paul A. Cummings    | Affirmative |   |
| 5 | City of Tallahassee   | Karen Webb          | Abstain     |   |
|   |   |                     |             | SUPPORTS THIRD PARTY  |

|   |  |                     |             |   |
|---|--|---------------------|-------------|---|
| 5 | Cleco Power  | Stephanie Huffman   | Negative    | COMMENTS - (See SPP Comments)   |
| 5 | Colorado Springs Utilities                         | Kaleb Brimhall      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)                    |
| 5 | Con Edison Company of New York                     | Brian O'Boyle       | Affirmative |   |
| 5 | Consumers Energy Company                           | David C Greyerbiehl | Negative    | COMMENT RECEIVED  |
| 5 | Cowlitz County PUD                                 | Bob Essex           | Affirmative |   |
| 5 | Dairyland Power Coop.                              | Tommy Drea          |             |   |
| 5 | Dominion Resources, Inc.                           | Mike Garton         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Dominion)                                      |
| 5 | DTE Electric                                       | Mark Stefaniak      | Abstain     |   |
| 5 | Duke Energy  | Dale Q Goodwine     | Affirmative |   |
| 5 | Dynegy Inc.  | Dan Roethemeyer     | Affirmative |   |
| 5 | E.ON Climate & Renewables North America, LLC       | Dana Showalter      | Abstain     |   |
| 5 | Entergy Services, Inc.                             | Tracey Stubbs       |             |   |
| 5 | Exelon Nuclear                                     | Mark F Draper       | Affirmative |   |
| 5 | First Wind   | John Robertson      |             |   |
| 5 | FirstEnergy Solutions                              | Kenneth Dresner     |             |   |
| 5 | Florida Municipal Power Agency                     | David Schumann      | Negative    | COMMENT RECEIVED  |
| 5 | Great River Energy                                 | Preston L Walsh     |             |   |
| 5 | Hydro-Québec Production                            | Roger Dufresne      | Abstain     |   |
| 5 | Independence Power & Light Dept.                   | James Nail          | Abstain     |   |
| 5 | Ingleside Cogeneration LP                          | Michelle R DAntuono | Negative    | COMMENT RECEIVED  |
| 5 | JEA  | John J Babik        |             |   |
| 5 | Kansas City Power & Light Co.                      | Brett Holland       | Affirmative |   |
| 5 | Kissimmee Utility Authority                        | Mike Blough         |             |   |
| 5 | Lakeland Electric                                  | James M Howard      |             |   |
| 5 | Liberty Electric Power LLC                         | Daniel Duff         |             |   |
| 5 | Lincoln Electric System                            | Dennis Florom       | Abstain     |   |
| 5 | Los Angeles Department of Water & Power            | Kenneth Silver      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPPA)   |
| 5 | Lower Colorado River Authority                     | Dixie Wells         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Martyn Turner, Lower Colorado River Authority) |
| 5 | Luminant Generation Company LLC                    | Rick Terrill        |             |   |
| 5 | Manitoba Hydro                                     | Chris Mazur         | Negative    | COMMENT RECEIVED  |
| 5 | Massachusetts Municipal Wholesale Electric Company | David Gordon        | Negative    | NO COMMENT RECEIVED   |
| 5 | MEAG Power   | Steven Grego        | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPPA)   |
| 5 | Muscatine Power & Water                            | Mike Avesing        | Abstain     |   |
| 5 | Nebraska Public Power District                     | Don Schmit          | Negative    | SUPPORTS THIRD PARTY COMMENTS - (SPP and Nebraska Public Power District)        |
| 5 | Nevada Power Co.                                   | Richard Salgo       | Affirmative |   |
| 5 | New York Power Authority                           | Wayne Sipperly      | Affirmative |   |
| 5 | NextEra Energy                                     | Allen D Schriver    | Affirmative |   |
| 5 | Northern Indiana Public Service Co.                | Michael D Melvin    |             |   |
| 5 | Oglethorpe Power Corporation                       | Bernard Johnson     | Affirmative |   |

|   |   |                    |             |  |
|---|---|--------------------|-------------|--|
| 5 | Oklahoma Gas and Electric Co.                             | Henry L Staples    | Negative    | NO COMMENT RECEIVED - (Supporting EEI's comments)            |
| 5 | Omaha Public Power District                               | Mahmood Z. Safi    | Negative    | COMMENT RECEIVED   |
| 5 | Orlando Utilities Commission                              | Richard K Kinas    |             |  |
| 5 | Pacific Gas and Electric Company                          | Alex Chua          |             |  |
| 5 | Platte River Power Authority                              | Christopher R Wood | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities) |
| 5 | Portland General Electric Co.                             | Matt E. Jastram    |             |  |
| 5 | PPL Generation LLC  | Annette M Bannon   | Affirmative |  |
| 5 | PSEG Fossil LLC   | Tim Kucey          | Affirmative |  |
| 5 | Public Utility District No. 1 of Lewis County             | Steven Grega       |             |  |
| 5 | Public Utility District No. 2 of Grant County, Washington | Michiko Sell       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA)                       |
| 5 | Puget Sound Energy, Inc.                                  | Lynda Kupfer       | Affirmative |  |
| 5 | Sacramento Municipal Utility District                     | Susan Gill-Zobitz  | Affirmative |  |
| 5 | Salt River Project  | William Alkema     | Affirmative |  |
| 5 | Santee Cooper   | Lewis P Pierce     | Abstain     |  |
| 5 | Seattle City Light  | Michael J. Haynes  |             |  |
| 5 | Seminole Electric Cooperative, Inc.                       | Brenda K. Atkins   |             |  |
| 5 | Snohomish County PUD No. 1                                | Sam Nietfeld       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA)                       |
| 5 | South Carolina Electric & Gas Co.                         | Edward Magic       | Affirmative |  |
| 5 | Southern California Edison Company                        | Denise Yaffe       | Affirmative |  |
| 5 | Southern Company Generation                               | William D Shultz   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Southern Company)           |
| 5 | Tacoma Power  | Chris Mattson      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)               |
| 5 | Tennessee Valley Authority                                | David Thompson     | Negative    | COMMENT RECEIVED   |
| 5 | Tri-State Generation & Transmission Association, Inc.     | Mark Stein         |             |  |
| 5 | U.S. Army Corps of Engineers                              | Melissa Kurtz      |             |  |
| 5 | USDI Bureau of Reclamation                                | Erika Doot         | Abstain     |  |
| 5 | Westar Energy   | Bryan Taggart      | Affirmative |  |
| 5 | Wisconsin Electric Power Co.                              | Linda Horn         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)             |
| 5 | Xcel Energy, Inc.   | Mark A Castagneri  | Affirmative |  |
| 6 | AEP Marketing   | Edward P. Cox      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)            |
| 6 | Ameren Missouri   | Robert Quinlivan   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Ameren)                     |
| 6 | APS   | Randy A. Young     | Affirmative |  |
| 6 | Associated Electric Cooperative, Inc.                     | Brian Ackermann    | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                       |
| 6 | Bonneville Power Administration                           | Brenda S. Anderson | Affirmative |  |
| 6 | Calpine Energy Services                                   | Agus Bintoro       |             |  |
|   |   |                    |             | SUPPORTS THIRD PARTY   |



|   |  |                       |             |  |
|---|--|-----------------------|-------------|--|
| 6 | City of Austin dba Austin Energy               | Lisa Martin           | Negative    | COMMENTS - (FMPA)  |
| 6 | City of Redding                                | Marvin Briggs         | Affirmative |  |
| 6 | Cleco Power LLC                                | Robert Hirschak       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)           |
| 6 | Colorado Springs Utilities                     | Shannon Fair          | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities) |
| 6 | Con Edison Company of New York                 | David Balban          | Affirmative |  |
| 6 | Constellation Energy Commodities Group         | David J Carlson       | Affirmative |  |
| 6 | Dominion Resources, Inc.                       | Louis S. Slade        | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Dominion)                   |
| 6 | Duke Energy                                    | Greg Cecil            | Affirmative |  |
| 6 | FirstEnergy Solutions                          | Kevin Querry          | Affirmative |  |
| 6 | Florida Municipal Power Agency                 | Richard L. Montgomery | Negative    | COMMENT RECEIVED   |
| 6 | Florida Municipal Power Pool                   | Thomas Reedy          | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA)                       |
| 6 | Florida Power & Light Co.                      | Silvia P Mitchell     | Affirmative |  |
| 6 | Kansas City Power & Light Co.                  | Jessica L Klinghoffer | Affirmative |  |
| 6 | Lakeland Electric                              | Paul Shipps           |             |  |
| 6 | Lincoln Electric System                        | Eric Ruskamp          | Abstain     |  |
| 6 | Los Angeles Department of Water & Power        | Brad Packer           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA) - (LADWP)             |
| 6 | Lower Colorado River Authority                 | Michael Shaw          | Negative    | COMMENT RECEIVED   |
| 6 | Luminant Energy                                | Brenda Hampton        | Abstain     |  |
| 6 | Manitoba Hydro                                 | Blair Mukanik         | Negative    | COMMENT RECEIVED   |
| 6 | Modesto Irrigation District                    | James McFall          | Affirmative |  |
| 6 | Muscatine Power & Water                        | John Stolley          |             |  |
| 6 | New York Power Authority                       | Shivaz Chopra         | Affirmative |  |
| 6 | New York State Electric & Gas Corp.            | Julie S King          |             |  |
| 6 | Northern Indiana Public Service Co.            | Joseph O'Brien        | Abstain     |  |
| 6 | Oglethorpe Power Corporation                   | Donna Johnson         | Affirmative |  |
| 6 | Oklahoma Gas and Electric Co.                  | Jerry Nottnagel       | Affirmative |  |
| 6 | Omaha Public Power District                    | Douglas Collins       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)               |
| 6 | PacifiCorp                                     | Sandra L Shaffer      | Negative    | COMMENT RECEIVED   |
| 6 | Platte River Power Authority                   | Carol Ballantine      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities) |
| 6 | Portland General Electric Co.                  | Shawn P Davis         | Affirmative |  |
| 6 | Powerex Corp.                                  | Gordon Dobson-Mack    |             |  |
| 6 | PPL EnergyPlus LLC                             | Elizabeth Davis       | Abstain     |  |
| 6 | PSEG Energy Resources & Trade LLC              | Peter Dolan           | Affirmative |  |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen          | Abstain     |  |
| 6 | Sacramento Municipal Utility District          | Diane Enderby         | Affirmative |  |
| 6 | Salt River Project                             | William Abraham       | Affirmative |  |
| 6 | Santee Cooper                                  | Michael Brown         | Abstain     |  |
| 6 | Seattle City Light                             | Dennis Sismaet        | Negative    | SUPPORTS THIRD PARTY COMMENTS -                              |

|    |   |                      |             |   |
|----|---|----------------------|-------------|---|
|    |   |                      |             | (Paul Haase)  |
| 6  | Seminole Electric Cooperative, Inc.                             | Trudy S. Novak       | Abstain     |   |
| 6  | Snohomish County PUD No. 1                                      | Kenn Backholm        | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(FMPPA)  |
| 6  | South Carolina Electric & Gas Co.                               | Matt H Bullard       | Affirmative |   |
| 6  | Southern California Edison Company                              | Joseph T Marone      | Affirmative |   |
| 6  | Southern Company Generation and Energy Marketing                | John J. Ciza         | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(Southern<br>Company)                          |
| 6  | Tacoma Public Utilities   | Michael C Hill       | Negative    | COMMENT<br>RECEIVED   |
| 6  | Tampa Electric Co.  | Benjamin F Smith II  |             |   |
| 6  | Tennessee Valley Authority                                      | Marjorie S. Parsons  | Negative    | COMMENT<br>RECEIVED   |
| 6  | Westar Energy   | Grant L Wilkerson    | Affirmative |   |
| 7  | Luminant Mining Company LLC                                     | Stewart Rake         |             |   |
| 7  | Occidental Chemical   | Venona Greaff        |             |   |
| 7  | Siemens Energy, Inc.  | Frank R. McElvain    |             |   |
| 8  |   | Roger C Zaklukiewicz |             |   |
| 8  |   | David L Kiguel       | Affirmative |   |
| 8  | Massachusetts Attorney General                                  | Frederick R Plett    |             |   |
| 8  | Volkman Consulting, Inc.  | Terry Volkman        | Affirmative |   |
| 9  | Central Lincoln PUD   | Bruce Lovelin        | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(Steve<br>Alexanderson,<br>Central<br>Lincoln) |
| 9  | Commonwealth of Massachusetts<br>Department of Public Utilities | Donald Nelson        | Abstain     |   |
| 9  | New York State Public Service Commission                        | Diane J Barney       |             |   |
| 10 | Midwest Reliability Organization                                | Russel Mountjoy      | Affirmative |   |
| 10 | New York State Reliability Council                              | Alan Adamson         | Affirmative |   |
| 10 | Northeast Power Coordinating Council                            | Guy V. Zito          | Affirmative |   |
| 10 | ReliabilityFirst  | Anthony E Jablonski  | Affirmative |   |
| 10 | SERC Reliability Corporation                                    | Joseph W Spencer     | Affirmative |   |
| 10 | Texas Reliability Entity, Inc.                                  | Karin Schweitzer     | Affirmative |   |
| 10 | Western Electricity Coordinating Council                        | Steven L. Rueckert   |             |   |

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**Individual or group. (53 Responses)**  
**Name (33 Responses)**  
**Organization (33 Responses)**  
**Group Name (20 Responses)**  
**Lead Contact (20 Responses)**  
**Question 1 (49 Responses)**  
**Question 1 Comments (49 Responses)**  
**Question 2 (44 Responses)**  
**Question 2 Comments (49 Responses)**  
**Question 3 (44 Responses)**  
**Question 3 Comments (49 Responses)**  
**Question 4 (47 Responses)**  
**Question 4 Comments (49 Responses)**  
**Question 5 (40 Responses)**  
**Question 5 Comments (49 Responses)**

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|  |
| Individual   |
| Aaron Staley   |
| Orlando Utilities Commission   |
| Yes  |
|  |
| No   |
|  |
| No   |
|  |
| No   |
| It is not clear what the status is of an RAS type system on nonBES facilities. For example a system that if installed at 230 kV would clearly be RAS, but is installed below 100kv. A system that only operates and protects nonBES facilities.  |
| Yes  |
|  |
| Individual   |
| Steve Alexanderson   |
| Central Lincoln  |
| Yes  |
|  |
| No   |
|  |
| No   |
|  |
| No   |
| Central Lincoln proposes the following be excluded: "Automatic transfer or system reconfiguration schemes intended to limit the extent and/or duration of outages; and not intended to benefit the BES." These systems operate similar to reclosing, in that they are intended to restore power quickly. Unlike reclosing, they may restore the power via an alternate path. We note the radial systems likely to benefit from auto-reconfiguration of load are unlikely to meet the BES definition, but the proposed definition of RAS has little dependency on the BES definition. The third RAS inclusion (Maintain acceptable System voltages) might be interpreted to include the auto-reconfiguration of load described above. |
| Yes  |
|  |

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|---|
| Group   |
| Northeast Power Coordinating Council  |
| Guy Zito  |
| Yes   |
| A single term will lead to a more consistent application of reliability standards.  |
| Yes   |
| The objective to "Meet requirements identified in the NERC Reliability Standards" improperly defines a NERC term by utilizing NERC requirements which can change over time. The purpose of this section is to describe the objectives of an RAS. An RAS is accomplished the objectives of adequate reliability. Those Standards and requirements that will apply to RAS will list RAS in their requirements. The final bullet in an RAS objective "Address other Bulk Electric System (BES) reliability concerns" is open ended. The previous bullets of voltage, stability, flows and Cascade are the hallmarks of adequate levels of reliability. To the existing definition of Special Protection System (Remedial Action Scheme), after "Such action may include changes in demand, generation (MW and Mvar)..." add the words HVDC power flows, FACTS device operating points,...  |
| Yes   |
| It is not clear why "unanticipated" was omitted from the first sentence of the definition. While it is true that at least in WECC most of the conditions its RASs detect are predetermined, in other regions that might not be the case and omission of the term creates a loophole that is not there now. A RAS is designed to respond to System Conditions that could happen. The schemes are developed in response to Planning Studies. Protection systems are not installed without considering the conditions that will activate them. First bullet: Have SPS/RAS requirements literally been identified in NERC standards, or is the intent that the SPS/RAS be applied so that the power system meets the performance requirements identified in the NERC reliability standards? Sixth bullet: What is a reliability "concern"? Wouldn't it be more accurate to say address other conditions that could otherwise result in failure to comply with reliability standards?  |
| No  |
| Regarding Item "c" (Undervoltage Load Shedding Programs [UVLS Programs]) of what does not individually constitute a RAS, UVLS Program must become an approved definition. Local undervoltage load shedding schemes that are not installed "to mitigate the risk of Cascading, voltage instability, voltage collapse, or uncontrolled separation resulting from undervoltage conditions" as defined in the draft PRC-010-1 should be excluded, therefore, "c. Undervoltage load Shedding Programs (UVLS Programs)" should be changed to "c. Automatic undervoltage load shedding schemes, including UVLS Programs. However, centrally controlled dispersed undervoltage load shedding schemes are RAS." An objective could be added to address centrally controlled Remedial Action Schemes. After the bulleted section, the sentence "The following do not individually constitute an RAS" could be read as implying that two or three of them taken together might constitute an RAS, which may or may not be the case. Suggest revising to read "The following do not individually, or combined in part or total, constitute a RAS." Please list UFLS and UVLS programs with the same capital letters and use of parentheses. |
| Yes   |
|   |
| Group   |
| Colorado Springs Utilities  |
| Kaleb Brimhall  |
| Yes   |
| RAS is good – we agree with having one term and do not have a preference on which term is used.   |
| No Comments   |
| No Comments   |
| No  |
| Colorado Springs Utilities does not agree with the exclusion list in the proposed definition. We do not think that it is reasonable or prudent to create a comprehensive list of exclusions. There will always be just one more exception that will force us to continue to modify the list of exclusions. Also, if it is not explicitly defined as an exception then by default it is automatically included whether it could  |

affect reliability or not. The definition should clearly define what a RAS so as to include those schemes identified as essential to reliability. The only implicit exclusion we would recommend would be to exclude protection schemes that meet the definition of a RAS and are explicitly covered under other NERC reliability standards. Utilities would then use the definition to make sure that essential protection systems that meet the definition are included and document any further assumptions or judgement used in delineating between RAS and non-RAS schemes. Trying to micro-manage every possible exclusion or inclusion we think is not realistic and should not be necessary. If we do keep the exclusions list then we would offer the following suggestions on the current list of exclusions, and would anticipate a fairly steady flow of additions/modifications to this list moving forward. 1. Remove "automatic" from UFLS 2. Should we explicitly exclude GMD responses? Refer to EOP-010-1/TPL-007-1.

No Comments

Individual

Michael Hill

Tacoma Public Utilities

No

Tacoma Power supports FMPA's comments concerning Question 1.

No

No

No

Tacoma Power supports FMPA's comments concerning Question 4. Furthermore, additional clarification seems necessary for (e): "Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service." Perhaps there could be another category for backing-up operator response and re-dispatch: "Locally sensing devices intended to mitigate thermal damage, within expected system re-dispatch response times, such as 10 minutes or greater. Examples are cooling fans, oil pumps, or thermal protection systems." Does the phrase "power system stabilizers" need to be explicitly added to (f)? In the FAQ document, on page 5 of 8, under "Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open," include something like the following two examples: (1) Opening the remote terminal(s) to remove an overload on the line in question following operation of the local terminal when there was no fault on the line in question and (2) opening the remote terminal(s) as a precaution against inadvertently closing back into a local island with generation.

No

Tacoma Power supports FMPA's comments concerning Question 5. Furthermore, in the FAQ document, on page 7 of 8, under "What are the Implementation Plan time frames," in the second paragraph, it should be 24 calendar months (or longer if the drafting team extends the timeframe) from the effective date (see page 6 of the Implementation Plan), not 24 calendar months beyond the date of approval by a governmental authority.

Individual

John Brockhan

CenterPoint Energy

Yes

No

No

Yes

(a) CenterPoint Energy believes the use of the capitalized term "UVLS Programs" is appropriate based upon the currently posted definition of "UVLS Program" that is proposed in NERC Project

2008-02 Undervoltage Load Shedding PRC-010-1. (b) CenterPoint Energy suggests changing "Autoreclosing schemes" to "Automatic reclosing schemes" (item d) to be consistent with other NERC documents, such as, Reliability Standard PRC-005-3 Protection System and Automatic Reclosing Maintenance. (c) The extensive list of what is not a RAS appears to be well developed with thirteen schemes specifically identified. However, with the opening sentence currently stating "The following do not individually constitute a RAS", it appears to be a finite list that would require a revision of the definition to include other possible control schemes. To not limit the list, CenterPoint Energy recommends the opening sentence be changed to "The following are examples of schemes that do not constitute a RAS". (d) CenterPoint Energy is concerned that the use of the term "individually" in the opening sentence, which currently states "The following do not individually constitute a RAS", reduces the clarity and specificity of the definition. Without clarity, this could result in inconsistent application across regions. As an example, if an entity has both a UVLS Program on their system and FACTS devices at a few locations, are these installations now considered to be collectively a RAS as opposed to individually? Under the existing NERC definition for SPS that states "An SPS does not include (a) underfrequency of Undervoltage load shedding", there would not be any confusion that these installations are not RAS. Of the thirteen items on the exclusions list, there is only one example (item d for autoreclosing) in the project FAQ document that provides insight of the team's intention with the use of "individually". CenterPoint Energy suggests deleting the word "individually" by changing the opening sentence to "The following are examples of schemes that do not constitute a RAS". Alternately, it may be possible to develop additional wording in the definition to codify the intent of the use of the term "individually". In addition, CenterPoint Energy recommends that the project FAQ document include additional examples to help clarify the intent. As an alternative to the FAQ document, NERC could instead develop an Applications Guidelines document, with specific examples, for the definition of RAS.

No

CenterPoint Energy recommends implementing the proposed definition of RAS and retirement of SPS as soon as practicable to incorporate the clarifications and help provide consistent application across all regions more quickly. Instead of 12 months, we suggest the definition become effective the first day of the first quarter after needed approvals. As this change would impact the proposed implementation plan time frame for newly-identified RAS resulting from the revised definition, we suggest changing the proposed twenty-four (24) months to thirty-six (36) months after the Effective Date of the definition.

Individual

Barbara Kedrowski

Wisconsin Electric Power Company

Yes

No

No

No

We recommend the following changes to the exclusions list a) through i), by item: e.) To simply include generator loss of field ignores many other generator protections for abnormal operating conditions. Revise this exclusions list to add the following: "Generator abnormal operating conditions listed in IEEE C37.102." (Or, list each individually, that is, "loss of field, unbalanced currents, loss of synchronism, overexcitation, motoring, over/under-voltage, and abnormal frequencies.") f.) This exclusion needs clarification. Does the clause "controllers that switch or regulate..." apply only to "series or shunt reactive devices", or does it extend to the rest of the items in this list? We suggest that the term "switch or regulate" creates ambiguity. We suggest simply using the term "controls ". Any controls for the various equipment listed should be excluded from being RAS. We also suggest that generator turbine controls be added to this list. j.) We propose that the SDT add a new item after item i), to include "Schemes that automatically shutdown a generator upon load rejection."

Yes

|  |
|--|
| Individual   |
| Kathy Caignon  |
| City of Vineland   |
| Yes  |
|  |
| Yes  |
| With the statement in the definition of "but are not limited to", and the first of the inclusions of "Meet requirements identified in the NERC Reliability Standards", there is no real limit on the scope of the definition. Also, the last inclusion "Address other BES reliability concerns" looks like a catchall inclusion that could be applied after the fact. This is not so black and white when talking about a definition of a RAS. There needs to be categorization and guidance for the industry to determine their own situations. Not all RAS (in the proposed definition) are equally critical to reliability of the BES.  |
| Yes  |
| Categorization of RAS for criticality.   |
| No   |
| Problems with determining a UVLS Program and RAS.  |
| No   |
|  |
| Individual   |
| Muhammed Ali   |
| Hydro One  |
| Yes  |
|  |
| No   |
|  |
| No   |
|  |
| No   |
| Local undervoltage load shedding schemes should be excluded, therefore, in the exclusion list, "c. Undervoltage load Shedding Programs (UVLS Programs)" should be changed to "c. Automatic undervoltage load shedding schemes, including UVLS Programs. However, centrally-controlled dispersed undervoltage load shedding schemes are RAS."   |
|  |
| Group  |
| MRO NERC Standards Review Forum  |
| Joe DePoorter  |
| Yes  |
|  |
| Yes  |
|  |
| Yes  |
| The definition as drafted includes use of Bulk Electric System in some places and not in others. Assuming the RAS that are covered under this standard are only those in the BES, the following changes are suggested to clarify this: A scheme designed to detect predetermined Bulk Electric System (BES) conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping BES generation or other BES sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives: • Meet requirements identified in the NERC Reliability Standards; • Maintain BES stability; • Maintain acceptable BES voltages; • Maintain acceptable BES power flows; • Limit the impact of BES Cascading; or • Address other BES reliability concerns To eliminate any doubt that the text used in |

NERC Reliability Standards properly applies to only BES Remedial Action Schemes. The NSRF recommends establishing a RAS Definition that applies explicitly to the BES. This objective could be accomplished by defining it as a "BES Remedial Action Scheme" and replacing the references to "System" with "BES". The existing references in the proposed RAS Definition to "System or Systems" apply more broadly to non-BES transmission systems and distribution systems.

No

The NSRF suggests: Item c – Consider rewording to better show the correlation to Item b by including the adjective 'automatic', with text like, "Automatic Undervoltage Load Shedding Programs (UVLS Programs) Item f – consider adding ". . . and controllers that . . ." to the middle of the item for improved readability. Item h – Consider using wording more aligned with Item g, such as ". . . remotely switch static shunt reactive devices for voltage regulation . . .". Otherwise consider wording like, "remotely switch static shunt inductors or static shunt capacitors for voltage regulation . . .".

Yes

Individual

John Pearson

ISO New England

No

Since the terms were defined the same and referenced each other, there is no need for the change. However, there is no harm in making the change either.

No

No

No

Exclusion "e." is too broad. There are instances where an overcurrent device that opens a line should be considered a RAS. As currently written, these schemes would fall under exclusion "e." and would no longer be considered RAS. Exclusion "j." should be limited depending on the size of the island, as determined by the Reliability Coordinator. For example, in some areas 800 MW may be small for a single dedicated facility, but in other areas, an 800 MW island could be substantial. Exclusion "m." should be limited to SSR protection schemes that act solely at the same station. It should read: "Sub-synchronous resonance (SSR) protection schemes that directly detect and act solely at the same station depending on sub-synchronous quantities (e.g. currents or torsional oscillations)." Another exclusion ("n.") should be added to exclude schemes that are specifically designed to restore load (often called load throw-over schemes) so that they are not considered RAS. An example of this is a 115-kV line that has load tapped off the middle. After a fault on the line, switches automatically open up at the tapped station and each end of the 115 kV line tries to pick up the load. The unfaulted end of the line will restore the load, and the faulted end will trip out and remain open. However, we do not believe that schemes which are taking actions such as automatic network reconfiguration to reenergize equipment that was tripped as a result of fault clearing which is not restoring load should be excluded.

No

24 months will be needed due to all the changes in documentation that will be required to address the revised definition.

Individual

David Thorne

Pepco Holdings Inc

Yes

No

No



|   |
|---|
| Yes   |
|   |
| Yes   |
|   |
| Individual  |
| Michelle DAntuono   |
| Ingleside Cogeneration LP   |
| No  |
| Ingleside Cogeneration LP (ICLP) believes that the second draft of the definition of a RAS is too open ended. Two modifications have been made to the base definition of a RAS that infer that almost any Protection System not specifically identified in the list of exclusions is in scope. First, the removal of the qualifier that RAS takes corrective action "other than the isolation of faulted elements" adds almost every relay scheme back into the equation. ICLP sees no good reason for its deletion – if there are such systems that isolate faulted elements and need RAS-like oversight, they should be explicitly listed. Second, the bulleted list under the base definition includes a catchall that stipulates that a RAS may address "other Bulk Electric System (BES) reliability concerns." We have seen ambiguous statements of this type lead to Regional variations, and have watched the original intent vary over time. As such, the item should be removed. In ICLP's view, the project team's decision to eliminate the four categories of RAS by function and extent of impact was also a step backwards. Several Regions have made similar distinctions of this type in order to account for variations in the most appropriate oversight methods – a tactic that has proven to be very effective. Furthermore, our reading of the stakeholder comments indicates that most respondents were comfortable with the concept, but had various concerns that were easily accommodated. As such, ICLP believes that the deferral of those distinctions to the individual NERC standards is too unstructured, and that the four original categories should be retained. |
| No  |
|   |
| Yes   |
| The exclusions proposed by the drafting team are comprehensive and precise – and the bulleted list of "inclusions" under the base definition of RAS must be as well. In the original definition, such descriptors included those RAS whose loss or malfunction would lead to "Non-Consequential Load Loss $\geq$ 300 MW", "Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection", "Loss of synchronism between two or more portions of the system each including more than one generating plant", and "Negatively damped oscillations". ICLP is not sure why specifics like this were removed to begin with – and we believe it is the responsibility of the drafting team to provide the rationale, not the industry.  |
| No  |
| If the core definition is not modified as ICLP proposes in response to Question 1, we believe that an exclusion must be made for a protective scheme that takes corrective action "other than the isolation of faulted elements". Without it, a relay owner will have to demonstrate to a CEA that they individually considered almost every relay system before determining that it is not a RAS. If there are such systems that isolate faulted elements and need RAS-like oversight, they can be explicitly listed under the core definition.  |
| Yes   |
|   |
| Individual  |
| Andrew Z.Pusztai  |
| American Transmission Company, LLC  |
| Yes   |
|   |
| No  |
|   |
| Yes   |

To eliminate any doubt that the text used in NERC Reliability Standards properly applies to only BES Remedial Action Schemes, ATC recommends establishing a RAS Definition that applies explicitly to the BES. This could be accomplished by defining it as a "BES Remedial Action Scheme" and replacing the references to "System" with "BES." The existing references in the proposed RAS Definition to "System" or "Systems" apply more broadly to non-BES transmission systems and distribution systems.

Yes

Yes

Individual

Amy Casuscelli

Xcel Energy

Yes

No

No

Yes

We also feel that sudden pressure relays (SPRs) should also be explicitly stated in item "e".

Yes

Group

Dominion

Louis Slade

Yes

No

No

The objectives do not belong in a definition of RAS. These objectives are a restatement of the NERC defined term "Reliable Operation" which is the objective of all Reliability Standards. . These are too broad and will cast to wide a net. "Meet the requirements identified in the NERC Reliability Standards" could include standards that are not developed yet. A RAS should only be a RAS if it solves a reliability violation for a specific contingency (not a generic "System condition") of the type stated in TPL-001-4 or its successor standard. Additionally, we are not sure if it should be a RAS if it only solves "extreme" events in the TPL standards since the label of RAS takes away incentive to mitigate problems.

No

From item "f", strike the term "and that are located at and monitor quantities solely at the same station as the Element being switched or regulated." Why does it make a difference whether the controller is local or remote? The advent of high-speed phase measurement units (PMUs) and faster computer systems will eventually allow wide area control. This will become essential as the customer's load characteristic evolves (less voltage and frequency dependency means local PSSs will be less effective). We are concerned that the definition in general will hamper innovation. Right now there are schemes that control LTC's and capacitors to minimize losses. Certainly these are not RAS. There are EMS controls such as what PJM uses that dispatch generation precontingency to avoid overloads/voltage problems. These are not RAS either. Eventually computer EMS systems will become fast and robust enough to drop load or reconfigure the system so quickly that wide area blackouts will be virtually eliminated. Recall that only 500 MWs of load drop would have stopped the

|   |
|---|
| 2003 blackout. Therefore wide area systems that generically react to problems (not designed for a single specific contingency (if line A opens, do xyz action)) should not be RAS.  |
| Yes   |
| Group   |
| Seattle City Light  |
| Paul Haase  |
| Yes   |
| No  |
| Seattle appreciates the efforts of the drafting team to be complete, but has concern with a definition that is primarily a negative definition, i.e. a definition of what a RAS is NOT. If such an approach is deemed the most practical, Seattle recommends that a general item be added to the list of what a RAS is not, such as "n. any other scheme that does not automatically act to maintain System performance or BES reliability on a wide area." The point is to have a general item that entities or auditors could point to, in the likely case that additional non-RAS schemes are identified that do not fall within the 13 "these are not a RAS" items identified so far.   |
| Individual  |
| Jo-Anne Ross  |
| Manitoba Hydro  |
| Yes   |
| Manitoba Hydro agrees that using a single term is the preferred approach. However, the proposed definition of "Remedial Action Scheme" is not clear. For example, it is not clear what "curtailing or tripping generation or other sources" means. Does it mean generation (real power) only but not reactive power? What does "other sources" refer to? The single term will take time getting used to in some regions that are used to SPS. However, there has always been confusion between protection systems and special protection system. A remedial action scheme is a better term.   |
| No  |
| No  |
| No  |
| 1. In the exclusion list a), it is not necessary to include power swing blocking 2. In the exclusion list e), it is not clear what "high voltage" here is intended to mean, does it mean overvoltage protection? Consider revise this as: "Schemes applied on an Element that react to non-Fault conditions, such as, but not limited to, generator loss-of-field protection, transformer top-oil temperature monitoring and protection, overvoltage protection, or overload protection to protect the Element itself against damage by removing it from service" 3. In exclusion list f), "switch or regulate" needs clarification, for example, what does "switch or regulate generation excitation" mean? Is converting a unit from a generator to a synchronous condenser considered as switching of generation excitation? Also, "at the same station" needs clarification. For example, if a generator switching station is less than 1 km away from its generating station, can they be considered as the same station? 4. The exclusion list covers transmission elements very well. One special transmission element missing is a braking resistor. Is use of a braking resistor a RAS or a permissible element used to maintain stability? Braking resistors are somewhat uncommon and could fall under the RAS definition. One special generator feature could be included in the exclusion list – fast valving. Fast valving is a common method used in steam turbines to improve stability and avoid generator tripping. |
| No  |
| The effective date for the revised Reliability Standards should be specific for each revised standard, and it should be specified in each revised standard.   |

|   |
|---|
| Individual  |
| Gary Kruempel   |
| MidAmerican Energy Company  |
| Yes   |
|   |
| No  |
|   |
| No  |
|   |
| No  |
| Exception "e" could be read to only include schemes that take the action of removing an element from service. If an action does something other than removing an element from service but its objective is to protect the element it should be included in this exception. Suggest removing the words "by removing it from service" be deleted from this exception.   |
| Yes   |
|   |
| Individual  |
| Jonathan Meyer  |
| Idaho Power   |
| Yes   |
|   |
| No  |
|   |
| No  |
|   |
| Yes   |
| We would like to see Protection System operations and fault clearing included as an exception. We feel this will better separate RAS actions from Protection System operations, e.g. fault clearing or generator loss of field tripping.  |
| Yes   |
| The initial 12 month period to identify new RAS appears to be adequate. However, the 24 month calendar should start once a new RAS is identified rather than the effective date of the definition.  |
| Individual  |
| Chris Scanlon   |
| Exelon Companies  |
| Yes   |
|   |
| No  |
|   |
| No  |
|   |
| No  |
| Exception "c" of the proposed definition of RAS excludes "UVLS Programs". The background information provided in the FAQ document suggests that the intent of using the term "UVLS Program" in this exclusion was to exclude UVLS schemes that are not centrally controlled. The Project 2008-02 Undervoltage Load Shedding drafting team states in their June 24, 2014 FAQ that UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators but not required by the planners do not meet the attributes of the proposed defined term "UVLS Program" and are therefore not subject to the requirements of PRC-010-1. This raises uncertainty as to whether such schemes, even if not centrally-controlled, are RAS, UVLS Programs, or neither. Please clarify whether exception "c" of the proposed definition of RAS would include a non-centrally- |

controlled UVLS scheme owned by a Transmission Owner, Distribution Provider, or Transmission Operator but not required by the Planning Coordinator or Transmission Planner, which is therefore not covered by the Project 2008-02 revisions to PRC-010. Exelon contends that such a scheme should not be considered a RAS.

Yes

Individual

Thomas Foltz

American Electric Power

Yes

AEP agrees with the concept of using a single term, and believes the project team is off to a good start in its development. AEP offers the following comments for continued improvement... It is unclear from the proposed definition and associated exclusions list whether automatic load rejection (ALR) of a generating unit is considered to be a Remedial Action Scheme. Our negative vote is driven solely on the lack of certainty surrounding this applicability of the definition. The qualifier "BES" should be incorporated into the definition as follows... Maintain \*BES\* System stability; Maintain acceptable \*BES\* System voltages; Maintain acceptable \*BES\* power flows; Limit the impact of \*BES\* Cascading; or

No

Once again, AEP believes the drafting team has done well in developing their exclusions list. As stated previously however, AEP believes it is unclear from the proposed definition and associated exclusions list whether automatic load rejection (ALR) of a generating unit is considered to be a Remedial Action Scheme. AEP believes that ALR is not an RAS and should be explicitly excluded in definition to avoid confusion.

Individual

Jamison Cawley

Nebraska Public Power District

Yes

No

No

Yes

No

Also, see SPP group comments The FAQ document states: "The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards." It appears the RAS classification types that are to be included in the RAS reliability standards will be a significant change that needs to be clarified before a full identification of RAS schemes and subsequent design requirements can be accurately completed if they are to be used. If other NERC standards must be updated or rewritten such as PRC or TPL standards in conjunction with this definition to clarify classification changes it is recommended the implementation plan specify that the proposed definition implementation not become effective until or following the most critically related RAS standards that would be updated in order to avoid confusion how the definition relates to existing or as yet un-revised standards. The FAQ document states "The Implementation Plan also provides owners of newly identified RAS twenty-four (24) calendar months beyond the date of approval by a

governmental authority to be fully compliant with all standards applicable to the revised definition of Remedial Action Scheme. The drafting team contends that twenty-four (24) calendar months provides the RAS owner sufficient time to become compliant with the revised standards proposed in the implementation Plan." If it is possible the RAS definition may include new schemes or require complete redundancy modifications near large generating plants that have long outage schedules due to any classification changes it seems the 2 year implementation time frame could be too short. It seems a minimum of 4 to 6 years for an implementation time frame would be more logical for modification changes based on the possible classification types. This would reduce the risk of unplanned or additional generation outages in order to meet this standard.

Group

SERC DRS

Robbie Bottoms

Individual

Anthony Jablonski

ReliabilityFirst

Yes

Yes

ReliabilityFirst submits the following comments for consideration: 1. Item k. "Automatic sequences that proceed when manually initiated solely by an operator" a. ReliabilityFirst is aware of a current RAS for a large generation plant in which the RAS can be armed/de-armed by a system operator. In the cases where this RAS is armed, we would consider this to be a RAS, applicable to any associated NERC Reliability Standards. ReliabilityFirst questions whether it is the intent of item "K" to exclude these types of schemes as a RAS. If so, what is the technical justification/basis for such exclusion? b. The term "operator" is undefined and may be left to interpretation. ReliabilityFirst recommends using the NERC Glossary of Terms definition of "System Operator" to further clarify the term "operator".

Individual

Michael Moltane

ITC

Yes

No

No

What purpose does the objectives list serve? Would any scheme be not considered RAS due to its objective? The term "other BES reliability concerns" seems to be all-inclusive so there's no point to the list.

Yes

Group

FirstEnergy Corp.

Richard Hoag

Yes

No

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| No   |
|  |
| Yes  |
| Exclusion "e", Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service. Please provide clarification on this exclusion.   |
| Yes  |
|  |
| Individual   |
| Mahmood Safi   |
| Omaha Public Power District  |
| Yes  |
|  |
| No   |
|  |
| Yes  |
| An objective of this project is to create a RAS definition and to eliminate the need for an SPS definition. Somewhere, that should be clarified.   |
| No   |
| The Omaha Public Power District (OPPD) believes that the exclusion list needs to be further clarified to state that the EMS/SCADA related schemes are not part of the RAS. Currently, this concern is addressed in the associated FAQ document; however, this document is not going to be part of the RAS Definition going forward. OPPD is concerned that lack of this clarity in the definition may cause inadvertent inclusion of schemes/systems that traditionally are not identified as RAS or SPS.  |
| Yes  |
|  |
| Group  |
| National Grid  |
| Michael Jones  |
| Yes  |
| While we agree with the desire to have a single term, both the proposed name "Remedial Action Scheme" (RAS) as well as the alternative term "Special Protection System" (SPS) seems to have issues. The definition does not say anything about how the action is accomplished. A problem we have is that, of the two names, "Remedial Action Scheme" seems to be worse, because a scheme usually mitigates a condition, but it does not usually remedy it. Strictly speaking, it performs a trade-off by substituting one abnormality, such as an open line or severed interconnection, for another, such as a thermally overloaded line. We are not arguing for one term or the other, but it is critical that the various terms be applied correctly and consistently. Further, the term "Special Protection System" at least implied that it took automatic action, whereas the term "Remedial Action Scheme" does not. A system operator operating a circuit breaker by remote control is a remedial scheme, but we do not think it falls under the scope of what is intended. Although the provision that it be automatic is included within the definition, it might be helpful to include it in the title as is done with underfrequency load shedding. |
|  |
| Yes  |
| RE: "RAS accomplish one or more of the following objectives: Maintain System Stability" Can a RAS/SPS maintain system stability or does it prevent (or at least lessen the odds of) system instability?  |
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|  |
| Group  |
| Operational Compliance   |

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| Dianne Gordon  |
| Yes  |
|  |
| No   |
|  |
| No   |
|  |
| No   |
| Part c. of Exclusions lists "Undervoltage Load Shedding Programs (UVLS Programs)". The definition of "UVLS Programs" needs to be clarified up front in the same space as the RAS definition. 1. The distinction between "centrally controlled UVLS" being included as part of the RAS definition and "locally controlled UVLS" not included in RAS Definition should be reclarified here. 2. The distinction between UVLS Program schemes and UVLS schemes that are not part of the entity "UVLS Program" also needs to be spelled out. For one intimately familiar with NERC standards, the information is available, but items 1. and 2. should be clear for a reader with somewhat limited knowledge of other standards. For example, engineers need to follow the NERC standards in their work, but may not be intimately familiar with other NERC standards, guidelines and definitions.  |
| Yes  |
|  |
| Individual   |
| Rich Salgo   |
| NV Energy  |
| Yes  |
|  |
| Yes  |
| The list of corrective actions taken by a RAS is comprehensive; however, we feel it would be a valuable improvement to clarify that each of the second through fifth bulleted items is applicable only to the BES. For instance, the second bullet would read "Maintain Bulk Electric System stability"; third bullet would read "Maintain acceptable BES voltages"; fourth bullet "Maintain acceptable BES power flows"; and fifth bullet "Limit the impact of Cascading throughout the BES".   |
| No   |
|  |
| Yes  |
|  |
| Yes  |
|  |
| Individual   |
| Patti Metro  |
| NRECA  |
| Yes  |
| Although NRECA agrees that using the single term RAS can provide clarity in the forty-three (43) standards utilizing the term, the proposed RAS definition creates a conflict with the applicability sections in the PRC-005-2 and PRC-005-3 standards. In these standards, the applicability 4.2.4 states "Protection Systems installed as a Special Protection System ...", but the proposed definition of a RAS explains that a RAS is no longer a "Protection System". With the proposed definition, PRC-005-2 and PRC-005-3 will not be applicable to a RAS. If these standards are meant to be applicable to the a RAS, then the applicability and possibly the associated requirements and tables included in PRC-005-2 and PRC-005-3 will require further revision rather than simply replacing SPS with RAS. NRECA recommends that the drafting team revisit the intent of designating that a RAS is not a "Protection System" which will require a thorough review of the standards to determine if a substitution creates a reliability gap by changing the intent of the modified standards. |
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| No  |
| Although NRECA does not believe that Automatic Generation Control (AGC) is a Remedial Action Scheme (RAS), the definition of AGC includes "automatically adjusts generation" which for some NRECA members is implied in the "curtailing generation" language included in the RAS definition. For clarity, consider including AGC in the list of exclusions.   |
| Individual  |
| David Jendras   |
| Ameren  |
| No  |
| The last bullet point in the definition of a Remedial Action Scheme "Address other Bulk Electric System (BES) reliability concerns." appears too broad, and we request the drafting team removed this from the definition.  |
| No  |
| No  |
| Yes   |
| Editorial: add semi-colon after each lettered item in the exclusion list.   |
| No  |
| (1) Direct substitution of RAS for SPS works in almost all cases, except for PRC-005-2, and - 3 section 4 Applicability 4.2.4 where it contradicts part of your proposed RAS definition "These schemes are not Protection Systems; however, they may share components with Protection Systems." We request the drafting team reword PRC-005-2 and -3 section 4.2.4 by adding 'Components' and 'part of' to yield the following: "Protection System Components installed as part of a Remedial Action Scheme (RAS) for BES reliability." (2) We request the drafting team to drop the word 'other' that's in front of 'protection systems' in PRC-012, PRC-013, PRC-014, PRC-015, and PRC-016 because it can be read to imply that a RAS is a protection system, which contradicts with part of your proposed RAS definition "These schemes are not Protection Systems; however, they may share components with Protection Systems." |
| Individual  |
| Martyn Turner   |
| LCRA Transmission Services Corporation  |
| Yes   |
| The following statement, "These schemes are not Protection Systems; however, they may share components with Protection Systems." is misleading and confusing. This statement should be deleted.   |
| No  |
| LCRA TSC recommends an additional example be included under the heading "The following do not individually constitute a RAS:" stated, "Protection systems installed to clear faults."   |
| No  |
| No  |
| LCRA TSC recommends an additional example be included under the heading "The following do not individually constitute a RAS:" stated, "Protection systems installed to clear faults." It appears that items F and G of the proposed definition are in conflict. Item G creates an exclusion that is taken away in item F for FACTS devices but leaves in place the limitation for switched shunts. LCRA TSC recommends revising items f. and g. as follows: f. Controllers that switch or regulate series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, tap-changing transformers, or generation excitation.   |
| Yes   |

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| Group  |
| Tennessee Valley Authority   |
| Brandy Spraker   |
| No   |
| We agree that using a single term should help bring the industry toward a common understanding/usage of the term. However, we believe the revised draft definition fails to add the desired clarity. We suggest the following modification: "A control scheme designed and installed to detect pre-analyzed System conditions and automatically perform corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives: <ul style="list-style-type: none"> <li>• Meet requirements identified in the NERC Reliability Standards;</li> <li>• Maintain System stability, as related to the NERC Reliability Standards;</li> <li>• Maintain acceptable System voltages, as related to the NERC Reliability Standards;</li> <li>• Maintain acceptable power flows, as related to the NERC Reliability Standards; or</li> <li>• Limit the impact of Cascading, as related to the NERC Reliability Standards.; or</li> </ul> DELETED: Address other Bulk Electric System (BES) reliability concerns. |
| No   |
|  |
| Yes  |
| The bulleted list of objectives fails to enhance clarity, and could in fact increase the uncertainty around RAS. Bullets 2-6 can be interpreted to cover objectives beyond NERC Reliability Standards, when taken in context with the first bullet. The scope of the definition should be limited to applications that are relevant to the NERC Reliability Standards in which the term is used. See proposed modifications under question 1 response.   |
| Yes  |
| We think it's appropriate to address exclusions, however when the exclusion list is this long (and perhaps growing) it highlights the challenge in developing a good base definition for what constitutes a RAS NERC-wide. An alternative would be to "catalog" the RAS exclusions in a separate NERC reference document that could be revised without revising the base RAS definition.   |
| Three years seems like a reasonable implementation period (a 1 year period for the definition to go into effect and a 2 year period for any existing scheme pulled into the definition to be brought into compliance). However, with 38 additional standards to be revised, this could entail more work than anticipated to ensure full compliance with each one under the new definition.   |
| Individual   |
| Richard Pienkos  |
| Consumers Energy Company   |
| No   |
| In general, we are encouraged with the redefinition of this scheme especially with the added clarity and emphasis on identifying that they are not Protection schemes but may share components. However, it is a little unclear if the intent of this definition was to define a term specifically for schemes applicable only to the BES or is the intent to have a broader definition and then restrict its applicability when used in each standard. To illustrate this point, in the first paragraph, the term "System" is used which in itself does not refer only to the BES. Yet in the list the objectives the RAS is to accomplish, the first item (Meet requirements identified in the NERC Standards) and the last item (address other BES reliability concerns) specifically refer to the applicability on the BES.  |
| Yes  |
| If the intent was indeed to have this definition apply only to the BES, then we suggest the additional clarifications since many companies may have similar schemes on non-applicable systems: A scheme designed to detect predetermined System conditions on the BES and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives: <ul style="list-style-type: none"> <li>• Meet requirements identified in the NERC Reliability Standards;</li> <li>• Maintain BES System stability;</li> <li>• Maintain acceptable BES System voltages;</li> <li>• Maintain acceptable BES power flows;</li> <li>• Limit the impact of Cascading on the BES; or</li> <li>• Address other Bulk Electric System (BES) reliability concerns.</li> </ul>   |

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| Yes  |
| If the intent was indeed to have a broader definition and then restrict its applicability when used in each standard, then we suggest the following clarifications: A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives: • Meet requirements identified in the NERC Reliability Standards; • Maintain System stability; • Maintain acceptable System voltages; • Maintain acceptable power flows; • Limit the impact of Cascading; or • Address other Bulk Electric System (BES) reliability concerns. Then each standard using this term would state something like "...an RAS used to address BES reliability..." to help define applicability in each standard.   |
| No   |
| We recommend that the first more restrictive definition that applies only to the BES be adopted. If this were done, then we would vote affirmative for this definition.  |
| Yes  |
|  |
| Group  |
| Duke Energy  |
| Colby Bellville  |
| Yes  |
|  |
| No   |
|  |
| No   |
|  |
| Yes  |
| Duke Energy does agree with the exclusion list, however, we request clarification on exclusion "a. Out of step tripping and power swing blocking." Does the exclusion apply when transfer trips and supervisory signals are used as an integral part of the Out of step tripping (OST) and power swing blocking (PSB) functions? It is possible to have an OST or a PSB and transfer a trip to many locations as part of that signal. It is also possible to have supervisory signals such as Voltage to enable the OST and PSB functions. A combination of signals and the transfer of signals are present, and we ask the standard drafting team if the intent was to exclude all of the possible functionalities/associated signals capable from an OST and PSB.  |
| Yes  |
|  |
| Individual   |
| Michael Shaw   |
| LCRA   |
| Group  |
| Florida Municipal Power Agency   |
| Frank Gaffney  |
| No   |
| FMPA is casting a Negative ballot for the RAS definition. FMPA is concerned with the following statement in the Remedial Action Schemes (RAS) definition: "These schemes are not Protection Systems; however, they may share components with Protection Systems." This sentence is confusing. RAS is a scheme and stating that it may share components with Protection Systems and at the same time terminating the use of the SPS reference is confusing. FMPA supports the intent of creating a RAS definition and believes the referenced statement should be deleted. Further, an additional example should be included under the heading, "The following do not individually constitute a RAS:" The addition may be worded something like, "Protection systems installed to clear faults are not RAS." FMPA suggests that a thorough look at all the uses of Protection System in the standards to determine if it was intended to include SPS/RAS as part of the requirement. (One |

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| example is PRC-005; the proposed definition specifically states that SPS/RAS is not a Protection System. Applicability of PRC-005-2 at 4.2.4 states: "Protection Systems installed as a Special Protection System ..." Since RAS/SPS is proposed to no longer be Protection Systems, this is a null set, removing RAS/SPS from PRC-005 creating an illogical statement of applicability. Note: some other instances where Protection System is used, that may be intended to include RAS, are: EOP-010, NUC-001, PER-005, PRC001, TPL-00x-0, the Glossary definition for Planning Authority, the definition for Protection System Maintenance Program.) |
| No  |
| No  |
| No  |
| The RAS definition is too broad as drafted and should specifically exclude control systems such as AGC, AVR, governor controls, etc. Suggested language is provided under number 1.   |
| No  |
| A thorough review of all the standards and their use of Protection Systems should be factored into the implementation plan.   |
| Group   |
| SERC Protection and Controls Subcommittee   |
| David Greene  |
| Yes   |
| No  |
| No  |
| Yes   |
| Yes   |
| The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.  |
| Group   |
| Associated Electric Cooperative, Inc. - JRO00088  |
| Phillip Hart  |
| Individual  |
| Catherine Wesley  |
| PJM Interconnection   |
| Yes   |
| No  |
| No  |
| Yes   |
| Yes   |
| Group   |
| IRC Standards Review Committee  |

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| Greg Campoli   |
| Yes  |
|  |
| Yes  |
| Reverse Power Sensing Relays should be added to the list of RAS.   |
| No   |
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| Yes  |
| Exclusion "m." should be limited to SSR protection schemes that act solely at the same station. It should read: "Sub-synchronous resonance that was tripped as a result of fault clearing which is not restoring load should be excluded Do you agree with the time frames in the proposed Implementation Plan associated with the onus resonance (SSR) protection schemes that directly detect and act solely at the same station depending on sub-synchronous quantities (e.g. currents or torsional oscillations)." Another exclusion ("n.") should be added to exclude schemes that are specifically designed to restore load (often called load throw-over schemes) so that they are not considered RAS. An example of this is a 115-kV line that has load tapped off the middle. After a fault on the line, switches automatically open up at the tapped station and each end of the 115 kV line tries to pick up the load. The unfaulted end of the line will restore the load, and the faulted end will trip out and remain open. However, we do not believe that schemes which are taking actions such as automatic network reconfiguration to reenergize equip |
| Yes  |
|  |
| Individual   |
| Mark Wilson  |
| Independent Electricity System Operator  |
| Yes  |
|  |
| No   |
|  |
| No   |
|  |
| Yes  |
|  |
| Yes  |
|  |
| Group  |
| Bonneville Power Administration  |
| Andrea Jessup  |
| Yes  |
|  |
| No   |
|  |
| No   |
|  |
| Yes  |
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| Yes  |
|  |
| Individual   |
| David Kiguel   |

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|---|
| N/A   |
| Group   |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing   |
| Wayne Johnson   |
| Yes   |
|   |
| No  |
|   |
| No  |
| The objective "Address other Bulk Electric System (BES) reliability concerns" is too broad. This encompasses every scheme on the system and makes the other objectives irrelevant. This objective should be deleted.  |
| No  |
| Additional words should be added to Exclusion e as follows: "Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by 1) removing it from service or 2) performing switching in the same substation as the Element to relieve the condition.   |
| Yes   |
|   |
| Individual  |
| Thomas Standifur  |
| Austin Energy   |
| No  |
| AE is casting a Negative ballot for the RAS definition. AE is concerned with the following statement in the Remedial Action Schemes (RAS) definition: "These schemes are not Protection Systems; however, they may share components with Protection Systems." This sentence is confusing. RAS is a scheme and stating that it may share components with Protection Systems and at the same time terminating the use of the SPS reference is confusing. AE supports the intent of creating a RAS definition and believes the referenced statement should be deleted. Further, an additional example should be included under the heading, "The following do not individually constitute a RAS:" The addition may be worded something like, "Protection systems installed to clear faults are not RAS." AE suggests that a thorough look at all the uses of Protection System in the standards to determine if it was intended to include SPS/RAS as part of the requirement. |
| No  |
|   |
| No  |
|   |
| No  |
| The RAS definition is too broad as drafted and should specifically exclude control systems such as AGC, AVR, governor controls, etc. Suggested language is provided under number 1.   |
| No  |
| A thorough review of all the standards and their use of Protection Systems should be factored into the implementation plan.   |
| Group   |
| SPP Standards Review Group  |
| Shannon V. Mickens  |
| Yes   |
| The single term 'RAS' reduces the confusion and ambiguities that the current interchangeable terms 'SPS/RAS' have created for the industry.   |

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| Yes  |
| We have a concern in reference to the term 'curtailed' being used in the revised definition. Our thought process associates 'curtailed' with the tagging process. The group suggests the term 'reduce' for it seems more fitting with the terms 'tripping of generation or load'.  |
| No   |
| We would suggest the removal of the first bullet 'Meet requirements identified in the NERC Reliability Standards' from the definition because the RAS shouldn't be implemented in reference to a particular Standard but for the operational needs of the system. Also, we recommend the removal of the last bullet 'Address other Bulk Electric System (BES) reliability concerns' to avoid the lack of clarity that was an issue with the original 'SPS/RAS' definition including it leaves the definition too open to interpretation.   |
| No   |
| The distinction between distributed and central controlled UVLS systems is not clear in the definition. The clarification is contained in the supporting documentation for the definition but requires extensive efforts to dig it out. We suggest the drafting team revise exclusion C in the proposed definition to provide more clarity.  |
| No   |
| We suggest extending the time frame from twenty-four (24) months to thirty-six (36) months. There are many elements that have to be considered when establishing a new RAS. For example, identifying new facilities/equipment, budgeting, outage coordination and receiving necessary approvals will require large amounts of time. We would like to commend the SPS SDT on the quality of the documents in this posting. We did not find a single typo/grammatical error that are so typically present in these postings. Well done and thank you.  |
| Group  |
| ACES Standards Collaborators   |
| Jason Marshall   |
| Yes  |
| (1) We agree with the need to modify the existing definition of SPS and RAS and that use of a single term will result in more consistent application of the standards. Furthermore, we are supportive of moving away from the SPS term to the RAS term to avoid confusion with Protection Systems and to more accurately reflect the intended purpose. The current definition lacks specificity, which leads to inconsistent application among the various NERC regions. We also note that the proposed changes have improved the RAS definition by removing some ambiguity. However, we believe there continues to remain to significant items of ambiguity that need to be addressed. Those are discussed below. (2) Use of the term "meet requirements identified in the NERC Reliability Standards" is ambiguous which will lead to inconsistent enforcement. Would this clause apply to any standard or is it intended primarily to apply to TPL standards? Does this require the owner of the RAS to document for which standards the RAS is installed? For a newly installed RAS, this might be easy but there could be disagreement over the purpose of the installation of existing RAS especially those that have been installed for a decade or more. We recommend removing the phrase from the definition. If the phrase persists, please identify specific standards and requirements in the technical guideline section for clarity. (3) Use of the term "address other Bulk Electric System (BES) reliability concern" is vague and ambiguous which will only lead to inconsistent enforcement. What other reliability concerns could there be besides system stability, system voltages, power flows, and Cascading that would not be excluded. Protecting equipment from damage would be one reliability concern that does not specifically fit into one of the categories but any schemes associated with protecting equipment from damage would be excluded by exclusion e. or excluded because they are Protection Systems. We simply cannot come up with any additional examples that warrant inclusion of such an ambiguity. We suggest the drafting team remove this phrase to remove the ambiguity. If there are other reliability concerns for which a RAS may be installed that do not fit into one of the five other buckets, then additional specific buckets should be added to avoid ambiguity. (4) "Relay" or "control" should be inserted just before scheme in the definition to provide additional clarity over what type of scheme is involved. (5) PRC-005-2 and PRC-005-3 will require further revision to the applicability section 4.2.4 other than simply replacing SPS with RAS to avoid ambiguity. The proposed definition of RAS specifically states that "these schemes are not Protection Systems." However, applicability section 4.2.4 states that it is applicable to "Protection Systems installed as a |

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| Remedial Action Scheme (RAS)" which directly conflicts with the definition. One could argue that PRC-005-2 and PRC-005-3 are then never applicable to a RAS once the new definition is approved since it is very specific that they are not Protection Systems.  |
| No   |
| We cannot identify any.  |
| No   |
| (1) We do not believe any additional objectives are necessary and believe that two objectives should be removed as discussed below. (2) Use of the term "meet requirements identified in the NERC Reliability Standards" is ambiguous which will lead to inconsistent enforcement. Would this clause apply to any standard or is it intended primarily to apply to TPL standards? Does this require the owner of the RAS to document for which standards the RAS is installed? For a newly installed RAS, this might be easy but there could be disagreement over the purpose of the installation of existing RAS especially those that have been installed for a decade or more. We recommend removing the phrase from the definition. If the phrase persists, please identify specific standards and requirements in the technical guideline section for clarity. (3) Use of the term "address other Bulk Electric System (BES) reliability concern" is vague and ambiguous which will only lead to inconsistent enforcement. What other reliability concerns could there be besides system stability, system voltages, power flows, and Cascading that would not be excluded. Protecting equipment from damage would be one reliability concern that does not specifically fit into one of the categories but any schemes associated with protecting equipment from damage would be excluded by exclusion e. or excluded because they are Protection Systems. We simply cannot come up with any additional examples that warrant inclusion of such an ambiguity. We suggest the drafting team remove this phrase to remove the ambiguity. If there are other reliability concerns for which a RAS may be installed that do not fit into one of the five other buckets, then additional specific buckets should be added to avoid ambiguity. (4) Because schemes could be interpreted to include AGC and excitation systems, the objectives could also inadvertently result in AGC or excitation systems being classified as RAS. AGC ultimately is required to meet several requirements in the BAL standards and excitation systems are used to control a generator's reactive power output to maintain an acceptable voltage schedule. Thus, both AGC and excitation systems support at least one of the objectives of the RAS definition. These objectives should ultimately be evaluated more closely. At the very least, AGC and excitation systems should be included in the exclusions list. |
| Yes  |
| We agree that the exclusion list is very detailed and helpful.   |
| Yes  |
| We agree with the time frame of 12 months after regulatory approval for the effective date of the standard. We also agree with the time frame for application of standards to newly identified RAS which is 24 months after the revised definition for newly identified RAS.   |
| Individual   |
| Gul Khan   |
| Oncor Electric Delivery LLC  |
| No   |
| Oncor disagrees with using RAS as a replacement for SPS. A SPS is used within ERCOT as an automatic system designed to detect abnormal or pre-determined ERCOT System conditions and take pre-planned corrective action. This term applies to and is referenced in numerous guides, procedures and protocols. Additionally the RAP (Remedial action plan) term is used in ERCOT and includes "controllable load shedding by dispatcher or ERCOT action." ERCOT's RAP's are predefined but not automatic and are used frequently within the system to maintain reliability under various operating conditions. Updating the various processes and procedures and training all the ERCOT TOPs on the new term will be a challenge and could cause significant confusion. The term SPS should not be based upon normal operational schemes like a RAS. These are "special" systems designed to maintain reliability until solutions can be added to remove or "exit" their changes. We also anticipate other reliability coordinators having to go through a similar effort in regards to the SPS terminology change.   |
| No   |



The SPS definition should be implemented as soon as possible the way it was originally developed by the NERC System Analysis and Modeling Subcommittee (SAMS) and approved by NERC OC PC. SAMS took several years developing the definition and getting approvals.

No

Yes

Yes

The RAP and SPS definition are already being used within ERCOT and apply to and are referenced in numerous guides, procedures and protocols. Many of ERCOT's RAP's are not automatic and are used frequently within the system to maintain reliability under various operating conditions. Updating SPS to the new term RAS through ERCOT's process of revising their documents will not only be a significant challenge but could also cause confusion with the RAP term.

Group

PacifiCorp

Sandra Shaffer

Yes

No

Yes

To clarify the intent of the proposed definition of Remedial Action Scheme, PacifiCorp recommends inserting Bulk Electric System into the first sentence as follows: "A scheme designed to detect predetermined Bulk Electric System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s)."

No

The proposed RAS definition will result in a significant expansion of the number of schemes that meet the criteria for classification as a RAS. In many instances, this expansion will not result in an improvement in Bulk Electric System reliability, and will unnecessarily complicate analysis of transmission system reliability. PacifiCorp recommends that the drafting team consider expansion of the exclusion list to include transfer- or cross-trip schemes that are located within a single substation. This exclusion would encompass schemes that operate from relays contained within substation apparatus to trip additional system elements other than those that are directly monitored by the relays with no additional logic or communications. As these schemes may be modeled with simple contingency definitions, PacifiCorp does not believe that their inclusion in the definition of RAS will provide any additional benefit for system reliability purposes. As stated in previous comments submitted to the drafting team by PacifiCorp on April 9, 2014, many common protection schemes that utilize breaker status contacts or lockout contacts to transfer trip multiple elements within a substation will meet the new SPS definition, despite limited potential impacts to the Bulk Electric System. For example, consider a scheme that utilizes a status contact on a line breaker to transfer-trip a shunt capacitor within the substation in conjunction with line tripping. In this example, the scheme is contained within the substation, and does not utilize any arming logic. The intent of the example scheme is to provide fast shunt device tripping and to provide additional redundancy for the shunt device voltage control. Under the draft definition, this scheme would meet the RAS criteria, as the shunt capacitor control is not based on locally-sensed voltage and system elements are tripped for a reason other than facilitation of fault clearing. Tripping of the capacitor could easily be modeled with a single line of code in a contingency definition, with the same results for system analysis and reliability purposes as inclusion in RAS databases. As such, this scheme and similar schemes that cross-trip various system elements within a single substation should have a specific exclusion in the proposed RAS definition. In addition, PacifiCorp recommends one specific change to the list of RAS exclusions. Exclusion "e" should include an Element in series as follows: "Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element or

|   |
|---|
| series Element against damage by removing it from service." It may be simpler and less costly to remove an Element in series with the overloaded Element rather than the overloaded Element itself.   |
| Yes   |
| Individual  |
| Sergio Banuelos   |
| Tri-State Generation and Transmission Association, Inc.   |
| Yes   |
| Although Tri-State agrees that using the single term RAS can provide clarity in the forty-three (43) standards utilizing the term, the proposed RAS definition creates a conflict with the applicability sections in the PRC-005-2 and PRC-005-3 standards. In these standards, the applicability 4.2.4 states "Protection Systems installed as a Special Protection System ...", but the proposed definition of a RAS explains that a RAS is no longer a "Protection System". With the proposed definition, PRC-005-2 and PRC-005-3 will not be applicable to a RAS. If these standards are meant to be applicable to the a RAS, then the applicability and possibly the associated requirements and tables included in PRC-005-2 and PRC-005-3 will require further revision rather than simply replacing SPS with RAS. Tri-State recommends that the drafting team revisit the intent of designating that a RAS is not a "Protection System" which will require a thorough review of the standards to determine if a substitution creates a reliability gap by changing the intent of the modified standards |
| No  |
| No  |
| No  |
| Although Tri-State does not believe that Automatic Generation Control (AGC) is a Remedial Action Scheme (RAS), the definition of AGC includes "automatically adjusts generation" which for some may be implied in the "curtailing generation" language included in the RAS definition. For clarity, consider including AGC in the list of exclusions  |
| Yes   |

# Consideration of Comments

## Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)

The Special Protection Systems Drafting Team thanks all commenters who submitted comments on the proposed definition of Remedial Action Scheme (RAS). These standards were posted for a 45-day public comment period from June 11, 2014 through July 25, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 53 sets of comments, including comments from approximately 159 different people from approximately 110 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's [project page](#).

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at [valerie.agnew@nerc.net](mailto:valerie.agnew@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

### Summary of Changes

#### Definition:

Changed the phrase “curtailing or tripping generation or other sources” to “adjusting or tripping generation (MW and Mvar)”

Changed the phrase “curtailing or tripping load” to “tripping load”

Changed the introductory sentence to the objectives from: “RAS accomplish one or more of the following objectives” to “RAS accomplish objectives such as” because the objective list is no longer all inclusive

Inserted “Bulk Electric System” (BES) as a qualifier in the pertinent objectives

Removed the last objective: “Address other Bulk Electric System (BES) reliability concerns” because it was deemed overly broad.

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<sup>1</sup> The appeals process is in the Standard Processes Manual:  
[http://www.nerc.com/comm/SC/Documents/Appendix\\_3A\\_StandardsProcessesManual.pdf](http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf)

Revised the fifth objective to read: “Limit the impact of Cascading or extreme event”

Removed the sentence: “These schemes are not Protection Systems; however, they may share components with Protection Systems.”

Added a new exclusion “a” that reads: “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements”

Combined exclusions “b” and “c” to read: “Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays”

Changed exclusion “d” from “Autoreclosing schemes” to “Automatic Reclosing schemes” to be in alignment with Reliability Standard PRC-05-3

In exclusion “e”, changed the term “high voltage” to “overvoltage”

In exclusion “f”, removed the term “generation excitation”

In exclusion “k”, replaced “operator” with the defined term “System Operator”

Added a new exclusion “n” that reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing”

### **Implementation Plan:**

Updated to add a specific Effective Date for PRC-024-1

Removed standards that are currently in implementation phase (these standards will be modified at a later date)

Removed retirement of “Special Protection System” (SPS) (the SPS definition will be needed until all references to SPS can be replaced with “Remedial Action Scheme” (RAS))

### **Background and FAQ:**

The Background and FAQ document was updated to reflect the changes and additions made to the proposed definition.

**Unresolved Minority Views:**

A few commenters questioned the general formatting of the definition and the need for an exclusion list.

The drafting team explained the definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS. Note, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety.

**1. Do you agree that using a single term; i.e., RAS, and clarifying its definition will lead to more consistent application of the related NERC Reliability Standards? If not, please provide specific suggestions and rationale .....16**

**2. Are there additional corrective actions that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale. ....31**

**3. Are there additional objectives that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale. ....39**

**4. Do you agree with the exclusion list in the proposed definition of RAS? If not, please provide specific suggestions and rationale.....50**

**5. Do you agree with the time frames in the proposed Implementation Plan associated with the proposed definition of RAS? Please provide specific comments in support of your position. ....72**

**The Industry Segments are:**

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

| Group/Individual  |                      | Commenter                                 | Organization                         | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |
|-------------------|----------------------|---|--------------------------------------|--------------------------------|---|---|---|---|---|---|---|---|----|
|                   |                      |   |                                      | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1.                | Group                | Guy Zito                                  | Northeast Power Coordinating Council |                                |   |   |   |   |   |   |   |   | X  |
| Additional Member |                      | Additional Organization                   | Region                               | Segment Selection              |   |   |   |   |   |   |   |   |    |
| 1.                | Alan Adamson         | New York State Reliability Council, LLC   | NPCC                                 | 10                             |   |   |   |   |   |   |   |   |    |
| 2.                | David Burke          | Orange and Rockland Utilities Inc.        | NPCC                                 | 3                              |   |   |   |   |   |   |   |   |    |
| 3.                | Greg Campoli         | New York Independent System Operator      | NPCC                                 | 2                              |   |   |   |   |   |   |   |   |    |
| 4.                | Sylvain Clermont     | Hydro-Quebec TransEnergie                 | NPCC                                 | 1                              |   |   |   |   |   |   |   |   |    |
| 5.                | Chris de Graffenried | Consolidated Edison Co. of New York, Inc. | NPCC                                 | 1                              |   |   |   |   |   |   |   |   |    |
| 6.                | Gerry Dunbar         | Northeast Power Coordinating Council      | NPCC                                 | 10                             |   |   |   |   |   |   |   |   |    |
| 7.                | Mike Garton          | Dominion Resources Services, Inc.         | NPCC                                 | 5                              |   |   |   |   |   |   |   |   |    |
| 8.                | Kathleen Goodman     | ISO - New England                         | NPCC                                 | 2                              |   |   |   |   |   |   |   |   |    |
| 9.                | Michael Jones        | National Grid                             | NPCC                                 | 1                              |   |   |   |   |   |   |   |   |    |
| 10.               | Mark Kenny           | Northeast Utilities                       | NPCC                                 | 1                              |   |   |   |   |   |   |   |   |    |

| Group/Individual           | Commenter                                 | Organization                     | Registered Ballot Body Segment |                          |   |   |   |   |   |   |   |    |  |  |
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|                            |   |                                  | 1                              | 2                        | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |
| 11. Peter Yost             | Consolidated Edison Co. of New York, Inc. | NPCC 3                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 12. Helen Lainis           | Independent Electricity System Operator   | NPCC 2                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 13. Alan MacNaughton       | New Brunswick Power Corporation           | NPCC 9                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 14. Bruce Metruck          | New York Power Authority                  | NPCC 6                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 15. Silvia Parada Mitchell | NextEra Energy, LLC                       | NPCC 5                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 16. Lee Pedowicz           | Northeast Power Coordinating Council      | NPCC 10                          |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 17. Robert Pellegrini      | The United Illuminating Company           | NPCC 1                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 18. Si Truc Phan           | Hydro-Quebec TransEnergie                 | NPCC 1                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 19. David Ramkalawan       | Ontario Power Generation, Inc.            | NPCC 5                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 20. Brian Robinson         | Utility Services                          | NPCC 8                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 21. Brian Shanahan         | National Grid                             | NPCC 1                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 22. Wayne Sipperly         | New York Power Authority                  | NPCC 5                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 23. Ayesha Sabouba         | Hydro One Networks Inc.                   | NPCC 1                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 24. Ben Wu                 | Orange and Rockland Utilities Inc .       | NPCC 1                           |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 2. Group                   | Kaleb Brimhall                            | Colorado Springs Utilities       | X                              |                          | X |   | X | X |   |   |   |    |  |  |
| N/A                        |   |                                  |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 3. Group                   | Joe DePoorter                             | MRO NERC Standards Review Forum  | X                              | X                        | X | X | X | X |   |   |   |    |  |  |
|                            | <b>Additional Member</b>                  | <b>Additional Organization</b>   | <b>Region</b>                  | <b>Segment Selection</b> |   |   |   |   |   |   |   |    |  |  |
| 1.                         | Amy Casucelli                             | Xcel Energy                      | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 2.                         | Chuck Wicklund                            | Otter Tail Power                 | MRO                            | 1, 3, 5                  |   |   |   |   |   |   |   |    |  |  |
| 3.                         | Dan Inman                                 | Minnkota Power Cooperative       | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 4.                         | Dave Rudolph                              | Basin Electric Power Cooperative | MRO                            |                          |   |   |   |   |   |   |   |    |  |  |
| 5.                         | Kayleigh Wilkerson                        | Lincoln Electric System          | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 6.                         | Jodi Jenson                               | WAPA                             | MRO                            | 1, 6                     |   |   |   |   |   |   |   |    |  |  |
| 7.                         | Joseph DePoorter                          | Madison Gas & Electric           | MRO                            | 3, 4, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 8.                         | Ken Goldsmith                             | Alliant Energy                   | MRO                            | 4                        |   |   |   |   |   |   |   |    |  |  |
| 9.                         | Mahmood Safi                              | Omaha Public Power District      | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 10.                        | Marie Knox                                | MISO                             | MRO                            | 2                        |   |   |   |   |   |   |   |    |  |  |
| 11.                        | Mike Brytowski                            | Great River Energy               | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 12.                        | Randi Nyholm                              | Minnesota Power                  | MRO                            | 1, 5                     |   |   |   |   |   |   |   |    |  |  |
| 13.                        | Terry Harbour                             | MidAmerican Energy               | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |



| Group/Individual         | Commenter                        | Organization       | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |  |  |
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|                          |                                  |                    | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |
| 14. Tom Breene           | Wisconsin Public Service         | MRO                | 3, 4, 5, 6                     |   |   |   |   |   |   |   |   |    |  |  |
| 15. Tony Eddleman        | Nebraska Public Power District   | MRO                |                                |   |   |   |   |   |   |   |   |    |  |  |
| 4. Group                 | Louis Slade                      | Dominion           |                                | X |   | X |   | X | X |   |   |    |  |  |
| <b>Additional Member</b> | <b>Additional Organization</b>   | <b>Region</b>      | <b>Segment Selection</b>       |   |   |   |   |   |   |   |   |    |  |  |
| 1. Mike Garton           | NERC Compliance Policy           | NPCC               | 5, 6                           |   |   |   |   |   |   |   |   |    |  |  |
| 2. Connie Lowe           | NERC Compliance Policy           | RFC                | 5, 6                           |   |   |   |   |   |   |   |   |    |  |  |
| 3. Randi Heise           | NERC Compliance Policy           | SERC               | 1, 3, 5, 6                     |   |   |   |   |   |   |   |   |    |  |  |
| 4. Chip Humphrey         | Power Generation Compliance      | NPCC               | 5                              |   |   |   |   |   |   |   |   |    |  |  |
| 5. Jarad L Morton        | Power Generation Compliance      | RFC                | 5                              |   |   |   |   |   |   |   |   |    |  |  |
| 6. Larry Whanger         | Power Generation Compliance      | SERC               | 5                              |   |   |   |   |   |   |   |   |    |  |  |
| 7. Larry Nash            | Electric Transmission Compliance | SERC               | 1, 3                           |   |   |   |   |   |   |   |   |    |  |  |
| 8. Jeffrey N Bailey      | Nuclear Compliance               |                    |                                |   |   |   |   |   |   |   |   |    |  |  |
| 5. Group                 | Paul Haase                       | Seattle City Light |                                | X |   | X | X | X | X |   |   |    |  |  |
| <b>Additional Member</b> | <b>Additional Organization</b>   | <b>Region</b>      | <b>Segment Selection</b>       |   |   |   |   |   |   |   |   |    |  |  |
| 1. Pawel Krupa           | Seattle City Light               | WECC               | 1                              |   |   |   |   |   |   |   |   |    |  |  |
| 2. Dana Wheelock         | Seattle City Light               | WECC               | 3                              |   |   |   |   |   |   |   |   |    |  |  |
| 3. Hao Li                | Seattle City Light               | WECC               | 4                              |   |   |   |   |   |   |   |   |    |  |  |
| 4. Mike Haynes           | Seattle City Light               | WECC               | 5                              |   |   |   |   |   |   |   |   |    |  |  |
| 5. Dennis Sismaet        | Seattle City Light               | WECC               | 6                              |   |   |   |   |   |   |   |   |    |  |  |
| 6. Group                 | Robbie Bottoms                   | SERC DRS           |                                |   |   |   |   |   |   |   |   |    |  |  |
| <b>Additional Member</b> | <b>Additional Organization</b>   | <b>Region</b>      | <b>Segment Selection</b>       |   |   |   |   |   |   |   |   |    |  |  |
| 1. Art Brown             |                                  | SERC               |                                |   |   |   |   |   |   |   |   |    |  |  |
| 2. John O'Connor         |                                  |                    |                                |   |   |   |   |   |   |   |   |    |  |  |
| 3. Tom Cain              |                                  |                    |                                |   |   |   |   |   |   |   |   |    |  |  |
| 4. Rick Foster           |                                  |                    |                                |   |   |   |   |   |   |   |   |    |  |  |
| 5. Robbie Bottoms        |                                  |                    |                                |   |   |   |   |   |   |   |   |    |  |  |
| 7. Group                 | Richard Hoag                     | FirstEnergy Corp.  |                                | X |   | X | X | X | X |   |   |    |  |  |
| <b>Additional Member</b> | <b>Additional Organization</b>   | <b>Region</b>      | <b>Segment Selection</b>       |   |   |   |   |   |   |   |   |    |  |  |
| 1. William Smith         | FlrstEnergy Corp                 | RFC                | 1                              |   |   |   |   |   |   |   |   |    |  |  |
| 2. Cindy Stewart         | FlrstEnergy Corp                 | RFC                | 3                              |   |   |   |   |   |   |   |   |    |  |  |

| Group/Individual  | Commenter                     | Organization                   | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |  |  |
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|   |                               |                                | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |
| 3. Doug Hohlbaugh   | Ohio Edison                   | RFC 4                          |                                |   |   |   |   |   |   |   |   |    |  |  |
| 4. Ken Dresner  | FirstEnergy Solutions         | RFC 5                          |                                |   |   |   |   |   |   |   |   |    |  |  |
| 5. Kevin Querry   | FirstEnergy Solutions         | RFC 6                          |                                |   |   |   |   |   |   |   |   |    |  |  |
| 6. Richard Hoag   | FirstEnergy Corp              | RFC NA                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 8. Group  | Michael Jones                 | National Grid                  | X                              |   | X |   |   |   |   |   |   |    |  |  |
| <b>Additional Member Additional Organization Region Segment Selection</b> |                               |                                |                                |   |   |   |   |   |   |   |   |    |  |  |
| 1. Brian Shanahan   | National Grid                 | NPCC 3                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 9. Group  | Dianne Gordon                 | Operational Compliance         | X                              |   | X |   | X |   |   |   |   |    |  |  |
| N/A   |                               |                                |                                |   |   |   |   |   |   |   |   |    |  |  |
| 10. Group   | Brandy Spraker                | Tennessee Valley Authority     | X                              |   | X |   | X | X |   |   |   |    |  |  |
| <b>Additional Member Additional Organization Region Segment Selection</b> |                               |                                |                                |   |   |   |   |   |   |   |   |    |  |  |
| 1. Brandy Spraker   |                               | SERC 5                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 2. Marjorie Parsons   |                               | SERC 6                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 3. Ian Grant  |                               | SERC 3                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 4. DeWayne Scott  |                               | SERC 1                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 11. Group   | Colby Bellville               | Duke Energy                    | X                              |   | X |   | X | X |   |   |   |    |  |  |
| <b>Additional Member Additional Organization Region Segment Selection</b> |                               |                                |                                |   |   |   |   |   |   |   |   |    |  |  |
| 1. Doug Hils  | Duke Energy                   | RFC 1                          |                                |   |   |   |   |   |   |   |   |    |  |  |
| 2. Lee Schuster   | Duke Energy                   | FRCC 3                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 3. Dale Goodwine  | Duke Energy                   | SERC 5                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 4. Greg Cecil   | Duke Energy                   | RFC 6                          |                                |   |   |   |   |   |   |   |   |    |  |  |
| 12. Group   | Frank Gaffney                 | Florida Municipal Power Agency | X                              |   | X | X | X | X |   |   |   |    |  |  |
| <b>Additional Member Additional Organization Region Segment Selection</b> |                               |                                |                                |   |   |   |   |   |   |   |   |    |  |  |
| 1. Tim Beyrle   | City of New Smyrna Beach      | FRCC 4                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 2. Jim Howard   | Lakeland Electric             | FRCC 3                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 3. Greg Woessner  | Kissimmee Utility Authority   | FRCC 3                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 4. Lynne Mila   | City of Clewiston             | FRCC 3                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 5. Cairo Vanegas  | Fort Pierce Utility Authority | FRCC 4                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 6. Randy Hahn   | Ocala Utility Service         | FRCC 3                         |                                |   |   |   |   |   |   |   |   |    |  |  |
| 7. Stanley Rzad   | Keys Energy Services          | FRCC 4                         |                                |   |   |   |   |   |   |   |   |    |  |  |

| Group/Individual  | Commenter                 | Organization                   | Registered Ballot Body Segment                   |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
|---|---------------------------|--------------------------------|--|---|---|---|---|---|---|---|---|----|--|--|--|--|--|--|--|--|-------------------|-------------------------|--------|-------------------|---------------------------------------|---------------------------|------|------|------------------------------|-------|------|------|-------------------------------------|------|------|------|--|-------|-------|------|--|------|------|------|--------------------------------------|--|------|------|
|   |                           |                                | 1  | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 8.  | Don Cuevas                | Beaches Energy Services        | FRCC   | 1 |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 9.  | Mark Schultz              | City of Green Cove Springs     | FRCC   | 3 |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 10.   | Tom Reedy                 | Florida Municipal Power Pool   | FRCC   | 6 |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 11.   | Steve Lancaster           | Beaches Energy Services        | FRCC   | 1 |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 12.   | Richard Bachmeier         | Gainesville Regional Utilities | FRCC   | 1 |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 13.   | Mike Blough               | Kissimmee Utility Services     | FRCC   | 3 |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 13.   | Group                     | David Greene                   | SERC Protection and Controls Subcommittee        |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
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| Additional Member   | Additional Organization   | Region                         | Segment Selection                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 1. Phil Winston   | Southern Company Services |                                |  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 2. George Pitts   | TVA                       |                                |  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 3. David Greene   | SERC                      |                                |  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 14.   | Group                     | Phillip Hart                   | Associated Electric Cooperative, Inc. - JRO00088 |   |   |   | X |   | X |   | X | X  |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
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| Additional Member   | Additional Organization   | Region                         | Segment Selection                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 1. Central Electric Power Cooperative   |                           | SERC                           | 1, 3   |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 2. KAMO Electric Cooperative  |                           | SERC                           | 1, 3   |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 3. M & A Electric Power Cooperative   |                           | SERC                           | 1, 3   |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 4. Northeast Missouri Electric Power Cooperative  |                           | SERC                           | 1, 3   |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 5. N.W. Electric Power Cooperative, Inc.  |                           | SERC                           | 1, 3   |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 6. Sho-Me Power Electric Cooperative  |                           | SERC                           | 1, 3   |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 15.   | Group                     | Greg Campoli                   | IRC Standards Review Committee                   |   |   |   |   | X |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
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| Additional Member   | Additional Organization   | Region                         | Segment Selection                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 1. Ben Li   | IESO                      | NPCC                           | 2  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 2. Matt Goldberg  | ISONE                     | NPCC                           | 2  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 3. Charles Yeung  | SPP                       | SPP                            | 2  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 4. Cheryl Moseley   | ERCOT                     | ERCOT                          | 2  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 5. Lori Spence  | MISO                      | RFC                            | 2  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 16.   | Group                     | Andrea Jessup                  | Bonneville Power Administration                  |   |   |   | X |   | X |   | X | X  |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
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| Additional Member   | Additional Organization   | Region                         | Segment Selection                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |
| 1. Chuck Matthews   | Transmission Planning     | WECC                           | 1  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |                   |                         |        |                   |                                       |                           |      |      |                              |       |      |      |                                     |      |      |      |  |       |       |      |  |      |      |      |                                      |  |      |      |

| Group/Individual | Commenter                  | Organization  | Registered Ballot Body Segment |                          |   |   |   |   |   |   |   |    |  |  |
|------------------|----------------------------|---|--------------------------------|--------------------------|---|---|---|---|---|---|---|----|--|--|
|                  |                            |   | 1                              | 2                        | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |
| 2. Jenny Wilson  | Transmission Planning      | WECC 1  |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 3. Dan Goodrich  | Technical Operations       | WECC 1  |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 4. Dean Bender   | System Control Engineering | WECC 1  |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 5. John Kerr     | Technical Operations       | WECC 1  |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 6. Heather Laslo | SPC Technical Svcs         | WECC 1  |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 17.              |                            | Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | X                              |                          | X |   | X | X |   |   |   |    |  |  |
|                  | Group                      | Wayne Johnson   |                                |                          |   |   |   |   |   |   |   |    |  |  |
| N/A              |                            |   |                                |                          |   |   |   |   |   |   |   |    |  |  |
| 18.              | Group                      | Shannon V. Mickens  | SPP Standards Review Group     |                          | X |   |   |   |   |   |   |    |  |  |
|                  | <b>Additional Member</b>   | <b>Additional Organization</b>  | <b>Region</b>                  | <b>Segment Selection</b> |   |   |   |   |   |   |   |    |  |  |
|                  | 1. Louis Guidry            | Cleco Power LLC   | SPP                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
|                  | 2. Greg Hill               | Nebraska Public Power District  | SPP                            | 1, 3, 5                  |   |   |   |   |   |   |   |    |  |  |
|                  | 3. Tiffany Lake            | Westar Energy, Inc  | SPP                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
|                  | 4. Stephanie Johnson       | Westar Energy, Inc  | SPP                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
|                  | 5. Bo Jones                | Westar Energy, Inc  | SPP                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
|                  | 6. Lynn Schroeder          | Westar Energy, Inc  | SPP                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
|                  | 7. Ron Losh                | Southwest Power Pool, Inc   | SPP                            | 2                        |   |   |   |   |   |   |   |    |  |  |
|                  | 8. James Nail              | City of Independence, Missouri  | SPP                            | 3                        |   |   |   |   |   |   |   |    |  |  |
|                  | 9. Robert Rhodes           | Southwest Power Pool, Inc   | SPP                            | 2                        |   |   |   |   |   |   |   |    |  |  |
|                  | 10. J.Scott Williams       | City Utilities of Springfield   | SPP                            | 1, 4                     |   |   |   |   |   |   |   |    |  |  |
|                  | 11. Mahmood Safi           | Omaha Public Power District   | SPP                            | 1, 3, 5                  |   |   |   |   |   |   |   |    |  |  |
|                  | 12. Ellen Watkins          | Sunflower Electric Power Corporation  | SPP                            | 1                        |   |   |   |   |   |   |   |    |  |  |
| 19.              | Group                      | Jason Marshall  | ACES Standards Collaborators   |                          |   |   |   |   | X |   |   |    |  |  |
|                  | <b>Additional Member</b>   | <b>Additional Organization</b>  | <b>Region</b>                  | <b>Segment Selection</b> |   |   |   |   |   |   |   |    |  |  |
|                  | 1. John Shaver             | Arizona Electric Power Cooperative  | WECC                           | 4, 5                     |   |   |   |   |   |   |   |    |  |  |
|                  | 2. John Shaver             | Southwest Transmission Cooperative  | WECC                           | 1                        |   |   |   |   |   |   |   |    |  |  |
|                  | 3. Shari Heino             | Brazos Electric Power Cooperative   | ERCOT                          | 1, 5                     |   |   |   |   |   |   |   |    |  |  |

| Group/Individual   | Commenter                            | Organization                       | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |   |   |
|--------------------|--------------------------------------|------------------------------------|--------------------------------|---|---|---|---|---|---|---|---|----|---|---|
|                    |                                      |                                    | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |   |   |
| 4. Mark Ringhausen | Old Dominion Electric Cooperative    | SERC 3, 4                          |                                |   |   |   |   |   |   |   |   |    |   |   |
| 5. Dick Chapman    | Prairie Power                        | SERC 3                             |                                |   |   |   |   |   |   |   |   |    |   |   |
| 6. Matt Caves      | Western Farmers Electric Cooperative | SPP 1, 5                           |                                |   |   |   |   |   |   |   |   |    |   |   |
| 20. Group          | Sandra Shaffer                       | PacifiCorp                         |                                |   |   |   |   |   |   |   |   |    |   |   |
| N/A                |                                      |                                    |                                |   |   |   |   |   |   |   |   |    |   |   |
| 21. Individual     | Aaron Staley                         | Orlando Utilities Commission       | X                              |   | X |   | X | X |   |   |   |    |   |   |
| 22. Individual     | Steve Alexanderson                   | Central Lincoln                    |                                |   | X | X |   |   |   |   |   |    | X |   |
| 23. Individual     | Michael Hill                         | Tacoma Public Utilities            | X                              |   | X | X | X | X |   |   |   |    |   |   |
| 24. Individual     | John Brockhan                        | CenterPoint Energy                 | X                              |   |   |   |   |   |   |   |   |    |   |   |
| 25. Individual     | Barbara Kedrowski                    | Wisconsin Electric Power Company   |                                |   | X | X | X |   |   |   |   |    |   |   |
| 26. Individual     | Kathy Caignon                        | City of Vineland                   |                                |   | X |   |   |   |   |   |   |    |   |   |
| 27. Individual     | Muhammed Ali                         | Hydro One                          | X                              |   | X |   |   |   |   |   |   |    |   |   |
| 28. Individual     | John Pearson                         | ISO New England                    |                                | X |   |   |   |   |   |   |   |    |   |   |
| 29. Individual     | David Thorne                         | Pepco Holdings Inc                 | X                              |   | X |   |   |   |   |   |   |    |   |   |
| 30. Individual     | Michelle DAntuono                    | Ingleside Cogeneration LP          |                                |   |   |   | X |   |   |   |   |    |   |   |
| 31. Individual     | Andrew Z.Pusztai                     | American Transmission Company, LLC | X                              |   |   |   |   |   |   |   |   |    |   |   |
| 32. Individual     | Amy Casuscelli                       | Xcel Energy                        | X                              |   | X |   | X | X |   |   |   |    |   |   |
| 33. Individual     | Jo-Anne Ross                         | Manitoba Hydro                     | X                              |   | X |   | X | X |   |   |   |    |   |   |
| 34. Individual     | Gary Kruempel                        | MidAmerican Energy Company         | X                              |   | X |   | X | X |   |   |   |    |   |   |
| 35. Individual     | Jonathan Meyer                       | Idaho Power                        | X                              |   |   |   |   |   |   |   |   |    |   |   |
| 36. Individual     | Chris Scanlon                        | Exelon Companies                   | X                              |   | X |   | X | X |   |   |   |    |   |   |
| 37. Individual     | Thomas Foltz                         | American Electric Power            | X                              |   | X |   | X | X |   |   |   |    |   |   |
| 38. Individual     | Jamison Cawley                       | Nebraska Public Power District     | X                              |   | X |   | X |   |   |   |   |    |   |   |
| 39. Individual     | Anthony Jablonski                    | ReliabilityFirst                   |                                |   |   |   |   |   |   |   |   |    |   | X |
| 40. Individual     | Michael Moltane                      | ITC                                | X                              |   |   |   |   |   |   |   |   |    |   |   |
| 41. Individual     | Mahmood Safi                         | Omaha Public Power District        | X                              |   | X |   | X | X |   |   |   |    |   |   |

| Group/Individual |            | Commenter        | Organization  | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |  |
|------------------|------------|------------------|---|--------------------------------|---|---|---|---|---|---|---|---|----|--|
|                  |            |                  |   | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |
| 42.              | Individual | Rich Salgo       | NV Energy   |                                |   |   |   | X |   |   |   |   |    |  |
| 43.              | Individual | Patti Metro      | NRECA   | X                              |   | X | X |   |   |   |   |   |    |  |
| 44.              | Individual | David Jendras    | Ameren  | X                              |   | X |   | X | X |   |   |   |    |  |
| 45.              | Individual | Martyn Turner    | LCRA Transmission Services Corporation                  | X                              |   |   |   | X | X |   |   |   |    |  |
| 46.              | Individual | Richard Pienkos  | Consumers Energy Company                                |                                |   | X | X | X |   |   |   |   |    |  |
| 47.              | Individual | Michael Shaw     | LCRA  |                                |   |   |   |   | X |   |   |   |    |  |
| 48.              | Individual | Catherine Wesley | PJM Interconnection                                     |                                | X |   |   |   |   |   |   |   |    |  |
| 49.              | Individual | Mark Wilson      | Independent Electricity System Operator                 |                                | X |   |   |   |   |   |   |   |    |  |
| 50.              | Individual | David Kiguel     | N/A   |                                |   |   |   |   |   |   | X |   |    |  |
| 51.              | Individual | Thomas Standifur | Austin Energy   | X                              |   | X |   | X |   | X |   |   |    |  |
| 52.              | Individual | Gul Khan         | Oncor Electric Delivery LLC                             | X                              |   |   |   |   |   |   |   |   |    |  |
| 53.              | Individual | Sergio Banuelos  | Tri-State Generation and Transmission Association, Inc. | X                              |   | X |   | X |   |   |   |   |    |  |

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

| Organization                                     | Agree | Supporting Comments of "Entity Name"   |
|--|-------|--|
| SERC DRS   | Agree |  |
| Associated Electric Cooperative, Inc. - JRO00088 | Agree | ACES   |
| LCRA   | Agree | <p>Lower Colorado River Authority-1. Do you agree that using a single term; i.e., RAS, and clarifying its definition will lead to more consistent application of the related NERC Reliability Standards? If not, please provide specific suggestions and rationale. YesComments: The following statement, "These schemes are not Protection Systems; however, they may share components with Protection Systems." is misleading and confusing. This statement should be deleted. 2. Are there additional corrective actions that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale. NoComments: LCRA TSC recommends an additional example be included under the heading "The following do not individually constitute a RAS:" stated, "Protection systems installed to clear faults." 3. Are there additional objectives that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale. NoComments:</p> |

| Organization | Agree | Supporting Comments of "Entity Name"  |
|--------------|-------|---|
|              |       | <p>4. Do you agree with the exclusion list in the proposed definition of RAS? If not, please provide specific suggestions and rationale. NoComments: LCRA TSC recommends an additional example be included under the heading "The following do not individually constitute a RAS:" stated, "Protection systems installed to clear faults." It appears that items F and G of the proposed definition are in conflict. Item G creates an exclusion that is taken away in item F for FACTS devices but leaves in place the limitation for switched shunts. LCRA TSC recommends revising items f. and g. as follows: f. Controllers that switch or regulate series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, tap-changing transformers, or generation excitation, and that are located at and monitor quantities solely at the same station as the Element being switched or regulated g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device</p> <p>5. Do you agree with the time frames in the proposed Implementation Plan associated with the proposed definition of RAS? Please provide specific comments in support of your position. Yes</p> |
| N/A          | Agree | NPCC  |



| Organization                   | Agree | Supporting Comments of "Entity Name" |
|--------------------------------|-------|--------------------------------------|
| Seattle City Light             |       | Florida Municipal Power Agency       |
| Nebraska Public Power District |       | SPP                                  |

**1. Do you agree that using a single term; i.e., RAS, and clarifying its definition will lead to more consistent application of the related NERC Reliability Standards? If not, please provide specific suggestions and rationale**

**Summary Consideration:**

By a four to one margin, commenters agreed with the drafting team that adopting and using the single term RAS across all of the eight NERC Regions, and clarifying its definition, will promote consistency in the application of the related NERC Reliability Standards.

Several commenters suggested the drafting team delete the statement “These schemes are not Protection Systems; however, they may share components with Protection Systems.” from the definition because it created some confusion with regards to the use of the term Protection Systems in other Reliability Standards. In response, the drafting team removed the statement from the definition.

There were numerous comments unrelated to this question that were addressed but not included in this summary.

| Organization               | Yes or No | Question 1 Comment  |
|----------------------------|-----------|---|
| Tennessee Valley Authority | No        | We agree that using a single term should help bring the industry toward a common understanding/usage of the term. However, we believe the revised draft definition fails to add the desired clarity. We suggest the following modification:” A control scheme designed and installed to detect pre-analyzed System conditions and automatically perform corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives: o Meet requirements identified in the NERC Reliability Standards; o Maintain System stability, as related to the NERC Reliability Standards; o Maintain acceptable System voltages, as related to the NERC Reliability Standards; o Maintain acceptable power flows, as related to the NERC Reliability Standards; or o Limit the impact of Cascading, as related to the NERC Reliability Standards.; or o DELETE: Address other Bulk Electric System (BES) reliability concerns. |

| Organization  | Yes or No | Question 1 Comment   |
|---|-----------|--|
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and revised the objectives by deleting the last bullet that read: "Address other Bulk Electric System (BES) reliability concerns" negating the all-inclusive nature of the objectives.</p> |           |  |
| <p>Florida Municipal Power Agency</p>   | <p>No</p> | <p>FMPA is casting a Negative ballot for the RAS definition.</p> <ol style="list-style-type: none"> <li>1) FMPA is concerned with the following statement in the Remedial Action Schemes (RAS) definition: "These schemes are not Protection Systems; however, they may share components with Protection Systems." This sentence is confusing. RAS is a scheme and stating that it may share components with Protection Systems and at the same time terminating the use of the SPS reference is confusing. FMPA supports the intent of creating a RAS definition and believes the referenced statement should be deleted.</li> <li>2) Further, an additional example should be included under the heading, "The following do not individually constitute a RAS:" The addition may be worded something like, "Protection systems installed to clear faults are not RAS."</li> <li>3) FMPA suggests that a thorough look at all the uses of Protection System in the standards to determine if it was intended to include SPS/RAS as part of the requirement. (One example is PRC-005; the proposed definition specifically states that SPS/RAS is not a Protection System. Applicability of PRC-005-2 at 4.2.4 states: "Protection Systems installed as a Special Protection System ..." Since RAS/SPS is proposed to no longer be Protection Systems, this is a null set, removing RAS/SPS from PRC-005 creating an illogical statement of applicability. Note: some other instances where Protection System is used, that may be intended to include RAS, are: EOP-010, NUC-001, PER-005, PRC001, TPL-00x-0, the Glossary definition for Planning Authority, the definition for Protection System Maintenance Program.)</li> </ol> |
| <p><b>Response:</b> Thank you for your comments.</p>  |           |  |

| Organization  | Yes or No | Question 1 Comment   |
|---|-----------|--|
| <p>1. To remove any confusion regarding the statement you identified, the drafting team deleted it from the definition.</p> <p>2. The drafting team agrees and added a new exclusion (a) which reads: Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements. The drafting team also added clarifying language in the FAQ.</p> <p>3. The removal of the aforementioned statement “These schemes are not Protection Systems; however, they may share components with Protection Systems.” should eliminate the need to review other Reliability Standards regarding the use of the term “Protection System(s).”</p> |           |  |
| Tacoma Public Utilities   | No        | Tacoma Power supports FMPA’s comments concerning Question 1.   |
| <p><b>Response:</b> Thank you for your comment. See the drafting team’s response to FMPA’s comments.</p>  |           |  |
| ISO New England   | No        | Since the terms were defined the same and referenced each other, there is no need for the change. However, there is no harm in making the change either.   |
| <p><b>Response:</b> Thank you for your comment.</p>   |           |  |
| Ingleside Cogeneration LP   | No        | <p>Ingleside Cogeneration LP (ICLP) believes that the second draft of the definition of a RAS is too open ended.</p> <p>1) Two modifications have been made to the base definition of a RAS that infer that almost any Protection System not specifically identified in the list of exclusions is in scope. First, the removal of the qualifier that RAS takes corrective action “other than the isolation of faulted elements” adds almost every relay scheme back into the equation. ICLP sees no good reason for its deletion - if there are such systems that isolate faulted elements and need RAS-like oversight, they should be explicitly listed.</p> <p>2) Second, the bulleted list under the base definition includes a catchall that stipulates that a RAS may address “other Bulk Electric System (BES) reliability concerns.” We have seen ambiguous statements of this type</p> |

| Organization  | Yes or No | Question 1 Comment   |
|---|-----------|--|
|   |           | <p>lead to Regional variations, and have watched the original intent vary over time. As such, the item should be removed.</p> <p>3) In ICLP’s view, the project team’s decision to eliminate the four categories of RAS by function and extent of impact was also a step backwards. Several Regions have made similar distinctions of this type in order to account for variations in the most appropriate oversight methods - a tactic that has proven to be very effective. Furthermore, our reading of the stakeholder comments indicates that most respondents were comfortable with the concept, but had various concerns that were easily accommodated. As such, ICLP believes that the deferral of those distinctions to the individual NERC standards is too unstructured, and that the four original categories should be retained.</p> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team agrees and added a new exclusion (a) which reads: Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements. The drafting team also added clarifying language in the FAQ.</li> <li>2. The drafting team agrees and revised the objectives by deleting the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns” negating the all-inclusive nature of the objectives.</li> <li>3. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.</li> </ol> |           |  |
| Ameren  | No        | <p>The last bullet point in the definition of a Remedial Action Scheme “Address other Bulk Electric System (BES) reliability concerns.” appears too broad, and we request the drafting team removed this from the definition.</p>  |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and revised the objectives by deleting the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns” negating the all-inclusive nature of the objectives.</p>   |           |  |

| Organization   | Yes or No | Question 1 Comment  |
|--|-----------|---|
| Consumers Energy Company   | No        | <p>In general, we are encouraged with the redefinition of this scheme especially with the added clarity and emphasis on identifying that they are not Protection schemes but may share components. However, it is a little unclear if the intent of this definition was to define a term specifically for schemes applicable only to the BES or is the intent to have a broader definition and then restrict its applicability when used in each standard. To illustrate this point, in the first paragraph, the term “System” is used which in itself does not refer only to the BES. Yet in the list the objectives the RAS is to accomplish, the first item (Meet requirements identified in the NERC Standards) and the last item (address other BES reliability concerns) specifically refer to the applicability on the BES.</p>  |
| <p><b>Response:</b> Thank you for your comment. The drafting team revised the objectives by deleting the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns” negating the all-inclusive nature of the objectives.</p> |           |   |
| Austin Energy  | No        | <p>AE is casting a Negative ballot for the RAS definition.</p> <ol style="list-style-type: none"> <li>1) AE is concerned with the following statement in the Remedial Action Schemes (RAS) definition: “These schemes are not Protection Systems; however, they may share components with Protection Systems.” This sentence is confusing. RAS is a scheme and stating that it may share components with Protection Systems and at the same time terminating the use of the SPS reference is confusing. AE supports the intent of creating a RAS definition and believes the referenced statement should be deleted.</li> <li>2) Further, an additional example should be included under the heading, “The following do not individually constitute a RAS:” The addition may be worded something like, “Protection systems installed to clear faults are not RAS.”</li> </ol> |

| Organization   | Yes or No | Question 1 Comment  |
|--|-----------|---|
|  |           | <p>3) AE suggests that a thorough look at all the uses of Protection System in the standards to determine if it was intended to include SPS/RAS as part of the requirement.</p>   |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>To remove any confusion regarding the statement you identified, the drafting team deleted it from the definition.</li> <li>The drafting team agrees and added a new exclusion (a) which reads: Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements.</li> <li>The removal of the aforementioned statement “These schemes are not Protection Systems; however, they may share components with Protection Systems.” should eliminate the need to review other Reliability Standards regarding the use of the term “Protection System(s).</li> </ol> |           |   |
| Oncor Electric Delivery LLC  | No        | <ol style="list-style-type: none"> <li>Oncor disagrees with using RAS as a replacement for SPS. A SPS is used within ERCOT as an automatic system designed to detect abnormal or pre-determined ERCOT System conditions and take pre-planned corrective action. This term applies to and is referenced in numerous guides, procedures and protocols.</li> <li>Additionally the RAP (Remedial action plan) term is used in ERCOT and includes “controllable load shedding by dispatcher or ERCOT action.” ERCOTs RAP’s are predefined but not automatic and are used frequently within the system to maintain reliability under various operating conditions. Updating the various processes and procedures and training all the ERCOT TOPs on the new term will be a challenge and could cause significant confusion.</li> <li>The term SPS should not be based upon normal operational schemes like a RAS. These are “special” systems designed to maintain reliability until solutions can be added to remove or “exit” their changes. We also anticipate other reliability coordinators having to go through a similar effort in regards to the SPS terminology change.</li> </ol> |

| Organization   | Yes or No | Question 1 Comment   |
|--|-----------|--|
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>The drafting team appreciates the fact that the selected term will cause some necessary documentation changes for entities but asserts that the use of the single term RAS will provide consistency and avoid the confusion associated with the SPS term.</li> <li>The drafting team acknowledges that entities will need time to adapt to the RAS term.</li> <li>The terms RAS and SPS are currently synonymous and interchangeable terms in the Glossary of Terms Used in NERC Reliability Standards.</li> </ol> |           |  |
| Northeast Power Coordinating Council   | Yes       | A single term will lead to a more consistent application of reliability standards.   |
| <p><b>Response:</b> Thank you for your comment and support.</p>  |           |  |
| Colorado Springs Utilities   | Yes       | RAS is good - we agree with having one term and do not have a preference on which term is used.  |
| <p><b>Response:</b> Thank you for your comment and support.</p>  |           |  |
| MRO NERC Standards Review Forum  | Yes       |  |
| Dominion   | Yes       |  |
| Seattle City Light   | Yes       |  |
| FirstEnergy Corp.  | Yes       |  |
| National Grid  | Yes       | <p>While we agree with the desire to have a single term, both the proposed name "Remedial Action Scheme" (RAS) as well as the alternative term "Special Protection System" (SPS) seems to have issues.</p> <ol style="list-style-type: none"> <li>The definition does not say anything about how the action is accomplished. A problem we have is that, of the two names, "Remedial</li> </ol> |



| Organization  | Yes or No | Question 1 Comment  |
|---|-----------|---|
|   |           | <p>Action Scheme" seems to be worse, because a scheme usually mitigates a condition, but it does not usually remedy it. Strictly speaking, it performs a trade-off by substituting one abnormality, such as an open line or severed interconnection, for another, such as a thermally overloaded line.</p> <p>2. We are not arguing for one term or the other, but it is critical that the various terms be applied correctly and consistently. Further, the term "Special Protection System" at least implied that it took automatic action, whereas the term "Remedial Action Scheme" does not. A system operator operating a circuit breaker by remote control is a remedial scheme, but we do not think it falls under the scope of what is intended. Although the provision that it be automatic is included within the definition, it might be helpful to include it in the title as is done with underfrequency load shedding.</p> |
| <p><b>Response:</b> Thank you for your comments.</p> <p>1. Currently, both terms, SPS and RAS, are used in the eight NERC Regions. The drafting team asserts that the use of the single term RAS will provide consistency and avoid the confusion associated with the SPS term. The drafting team therefore recommends that the term RAS be retained as the industry-recognized term and that the term SPS be retired as soon as possible.</p> <p>2. The term "Remedial Action Scheme" (RAS) is a long-standing alternative term for "Special Protection System" (SPS) in the Glossary of Terms Used in NERC Reliability Standards, as such NERC already recognizes RAS as an "automatic" scheme.</p> |           |   |
| Operational Compliance  | Yes       |   |
| Duke Energy   | Yes       |   |
| SERC Protection and Controls Subcommittee   | Yes       |   |
| IRC Standards Review Committee  | Yes       |   |

| Organization  | Yes or No | Question 1 Comment  |
|---|-----------|---|
| Bonneville Power Administration   | Yes       |   |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes       |   |
| SPP Standards Review Group  | Yes       | The single term 'RAS' reduces the confusion and ambiguities that the current interchangeable terms 'SPS/RAS' have created for the industry.   |
| <b>Response:</b> Thank you for your comment and support.  |           |   |
| ACES Standards Collaborators  | Yes       | <p>We agree with the need to modify the existing definition of SPS and RAS and that use of a single term will result in more consistent application of the standards. Furthermore, we are supportive of moving away from the SPS term to the RAS term to avoid confusion with Protection Systems and to more accurately reflect the intended purpose. The current definition lacks specificity, which leads to inconsistent application among the various NERC regions. We also note that the proposed changes have improved the RAS definition by removing some ambiguity. However, we believe there continues to remain to significant items of ambiguity that need to be addressed. Those are discussed below.</p> <ol style="list-style-type: none"> <li>1. Use of the term “meet requirements identified in the NERC Reliability Standards” is ambiguous which will lead to inconsistent enforcement. Would this clause apply to any standard or is it intended primarily to apply to TPL standards? Does this require the owner of the RAS to document for which standards the RAS is installed? For a newly</li> </ol> |

| Organization | Yes or No | Question 1 Comment   |
|--------------|-----------|--|
|              |           | <p>installed RAS, this might be easy but there could be disagreement over the purpose of the installation of existing RAS especially those that have been installed for a decade or more. We recommend removing the phrase from the definition. If the phrase persists, please identify specific standards and requirements in the technical guideline section for clarity.</p> <ol style="list-style-type: none"> <li>2. Use of the term “address other Bulk Electric System (BES) reliability concern” is vague and ambiguous which will only lead to inconsistent enforcement. What other reliability concerns could there be besides system stability, system voltages, power flows, and Cascading that would not be excluded. Protecting equipment from damage would be one reliability concern that does not specifically fit into one of the categories but any schemes associated with protecting equipment from damage would be excluded by exclusion e. or excluded because they are Protection Systems. We simply cannot come up with any additional examples that warrant inclusion of such an ambiguity. We suggest the drafting team remove this phrase to remove the ambiguity. If there are other reliability concerns for which a RAS may be installed that do not fit into one of the five other buckets, then additional specific buckets should be added to avoid ambiguity.</li> <li>3. “Relay” or “control” should be inserted just before scheme in the definition to provide additional clarity over what type of scheme is involved.</li> <li>4. PRC-005-2 and PRC-005-3 will require further revision to the applicability section 4.2.4 other than simply replacing SPS with RAS to avoid ambiguity. The proposed definition of RAS specifically states that “these schemes are not Protection Systems.” However, applicability section 4.2.4 states that it is applicable to “Protection Systems installed as a Remedial Action Scheme (RAS)” which directly conflicts with the definition. One could argue that PRC-005-2 and PRC-005-3 are then</li> </ol> |

| Organization  | Yes or No | Question 1 Comment  |
|---|-----------|---|
|   |           | never applicable to a RAS once the new definition is approved since it is very specific that they are not Protection Systems. |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team contends that the requested level of specificity regarding the NERC Reliability Standards is not appropriate. It is important that the scope of the definition include schemes whose failure to operate or whose misoperation may pose a reliability risk. Listing specific standards may unintentionally limit the scope of the definition. The definition by itself imposes no requirements on RAS owners.</li> <li>2. The drafting team agrees and revised the objectives by deleting the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns” negating the all-inclusive nature of the objectives.</li> <li>3. The drafting team disagrees and declines to make the suggested change so as not to unnecessarily limit the scope of the definition.</li> <li>4. To remove any confusion regarding the statement you identified, the drafting team deleted the statement from the definition.</li> </ol> |           |   |
| PacifiCorp  | Yes       |   |
| Orlando Utilities Commission  | Yes       |   |
| Central Lincoln   | Yes       |   |
| CenterPoint Energy  | Yes       |   |
| Wisconsin Electric Power Company  | Yes       |   |
| City of Vineland  | Yes       |   |
| Hydro One   | Yes       |   |
| Pepco Holdings Inc  | Yes       |   |
| American Transmission Company, LLC  | Yes       |   |

| Organization  | Yes or No | Question 1 Comment   |
|---|-----------|--|
| Xcel Energy   | Yes       |  |
| Manitoba Hydro  | Yes       | <ol style="list-style-type: none"> <li>1. Manitoba Hydro agrees that using a single term is the preferred approach. However, the proposed definition of “Remedial Action Scheme” is not clear. For example, it is not clear what “curtailing or tripping generation or other sources” means. Does it mean generation (real power) only but not reactive power?</li> <li>2. What does “other sources” refer to? The single term will take time getting used to in some regions that are used to SPS. However, there has always been confusion between protection systems and special protection system. A remedial action scheme is a better term.</li> </ol> |
| <p>Response: Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team revised the first sentence of the definition to read: “A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s).” “Generation” is both real and reactive power.</li> <li>2. The drafting team removed the phrase “other sources.”</li> </ol> |           |  |
| MidAmerican Energy Company  | Yes       |  |
| Idaho Power   | Yes       |  |
| Exelon Companies  | Yes       |  |
| American Electric Power   | Yes       | <p>AEP agrees with the concept of using a single term, and believes the project team is off to a good start in its development. AEP offers the following comments for continued improvement...</p> <ol style="list-style-type: none"> <li>1. It is unclear from the proposed definition and associated exclusions list whether automatic load rejection (ALR) of a generating unit is considered to be a Remedial Action Scheme.</li> </ol>  |

| Organization  | Yes or No | Question 1 Comment  |
|---|-----------|---|
|   |           | <p>2. Our negative vote is driven solely on the lack of certainty surrounding this applicability of the definition. The qualifier “BES” should be incorporated into the definition as follows...Maintain *BES* System stability; Maintain acceptable *BES* System voltages; Maintain acceptable *BES* power flows; Limit the impact of *BES* Cascading; or</p>  |
| <p><b>Response:</b> Thank you for your comments.</p> <p>1. An automatic load rejection scheme (ALR) may or may not be a RAS depending upon the application details. AEP has not provided enough details in the comment for the drafting team to make a determination.</p> <p>2. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives.</p> |           |   |
| Nebraska Public Power District  | Yes       |   |
| ReliabilityFirst  | Yes       |   |
| ITC   | Yes       |   |
| Omaha Public Power District   | Yes       |   |
| NV Energy   | Yes       |   |
| NRECA   | Yes       | <p>Although NRECA agrees that using the single term RAS can provide clarity in the forty-three (43) standards utilizing the term, the proposed RAS definition creates a conflict with the applicability sections in the PRC-005-2 and PRC-005-3 standards. In these standards, the applicability 4.2.4 states "Protection Systems installed as a Special Protection System ...", but the proposed definition of a RAS explains that a RAS is no longer a “Protection System”. With the proposed definition, PRC-005-2 and PRC-005-3 will not be applicable to a RAS. If these standards are meant to be applicable to the a RAS, then the applicability and possibly the associated requirements and tables included in PRC-005-2 and PRC-005-3 will require further revision</p> |

| Organization  | Yes or No | Question 1 Comment   |
|---|-----------|--|
|   |           | rather than simply replacing SPS with RAS. NRECA recommends that the drafting team revisit the intent of designating that a RAS is not a “Protection System” which will require a thorough review of the standards to determine if a substitution creates a reliability gap by changing the intent of the modified standards.  |
| <p><b>Response:</b> Thank you for your comment. To remove any confusion regarding the statement you identified, the drafting team deleted it from the definition. The removal of the aforementioned statement should eliminate the need to review other Reliability Standards regarding the use of the term “Protection System(s).”</p> |           |  |
| LCRA Transmission Services Corporation  | Yes       | The following statement, “These schemes are not Protection Systems; however, they may share components with Protection Systems.” is misleading and confusing. This statement should be deleted.  |
| <p><b>Response:</b> Thank you for your comment. To remove any confusion regarding the statement you identified, the drafting team deleted it from the definition.</p>   |           |  |
| PJM Interconnection   | Yes       |  |
| Independent Electricity System Operator   | Yes       |  |
| Tri-State Generation and Transmission Association, Inc.   | Yes       | Although Tri-State agrees that using the single term RAS can provide clarity in the forty-three (43) standards utilizing the term, the proposed RAS definition creates a conflict with the applicability sections in the PRC-005-2 and PRC-005-3 standards. In these standards, the applicability 4.2.4 states "Protection Systems installed as a Special Protection System ...", but the proposed definition of a RAS explains that a RAS is no longer a “Protection System”. With the proposed definition, PRC-005-2 and PRC-005-3 will not be applicable to a RAS. If these standards are meant to be applicable to the a RAS, then the applicability and possibly the associated requirements and tables included in PRC-005-2 and PRC-005-3 will require further revision |

| Organization   | Yes or No | Question 1 Comment   |
|--|-----------|--|
|  |           | rather than simply replacing SPS with RAS. Tri-State recommends that the drafting team revisit the intent of designating that a RAS is not a "Protection System" which will require a thorough review of the standards to determine if a substitution creates a reliability gap by changing the intent of the modified standards |
| <p><b>Response:</b> Thank you for your comment. To remove any confusion regarding the statement you identified, the drafting team deleted it from the definition. The removal of the aforementioned statement should eliminate the need to review other Reliability Standards regarding the use of the term "Protection System(s).</p> |           |  |



**2. Are there additional corrective actions that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale.**

**Summary Consideration:**

Approximately 80% of commenters agreed with the corrective actions included in the proposed definition of RAS.

A few commenters requested the clarity around the phrase “curtailing or tripping generation or other sources.” The drafting team changed “curtailing” to “adjusting” because “curtailing” is associated with electronic tagging; and replaced “other sources” with “(MW and Mvar)” to clarify that generation includes both real and reactive power.

There were numerous comments unrelated to this question that were addressed but not included in this summary.

| Organization                              | Yes or No | Question 2 Comment |
|---|-----------|--------------------|
| Dominion                                  | No        |                    |
| FirstEnergy Corp.                         | No        |                    |
| Operational Compliance                    | No        |                    |
| Tennessee Valley Authority                | No        |                    |
| Duke Energy                               | No        |                    |
| Florida Municipal Power Agency            | No        |                    |
| SERC Protection and Controls Subcommittee | No        |                    |
| Bonneville Power Administration           | No        |                    |

| Organization  | Yes or No | Question 2 Comment      |
|---|-----------|-------------------------|
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | No        |                         |
| ACES Standards Collaborators  | No        | We cannot identify any. |
| PacifiCorp  | No        |                         |
| Orlando Utilities Commission  | No        |                         |
| Central Lincoln   | No        |                         |
| Tacoma Public Utilities   | No        |                         |
| CenterPoint Energy  | No        |                         |
| Wisconsin Electric Power Company  | No        |                         |
| Hydro One   | No        |                         |
| ISO New England   | No        |                         |
| Pepco Holdings Inc  | No        |                         |

| Organization  | Yes or No | Question 2 Comment  |
|---|-----------|---|
| Ingleside Cogeneration LP   | No        |   |
| American Transmission Company, LLC  | No        |   |
| Xcel Energy   | No        |   |
| Manitoba Hydro  | No        |   |
| MidAmerican Energy Company  | No        |   |
| Idaho Power   | No        |   |
| Exelon Companies  | No        |   |
| Nebraska Public Power District  | No        |   |
| ITC   | No        |   |
| Omaha Public Power District   | No        |   |
| Ameren  | No        |   |
| LCRA Transmission Services Corporation  | No        | LCRA TSC recommends an additional example be included under the heading “The following do not individually constitute a RAS:” stated, “Protection systems installed to clear faults.” |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and added a new exclusion (a) which reads: Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements. The drafting team also added clarifying language in the FAQ.</p> |           |   |

| Organization   | Yes or No | Question 2 Comment   |
|--|-----------|--|
| PJM Interconnection  | No        |  |
| Independent Electricity System Operator  | No        |  |
| Austin Energy  | No        |  |
| Oncor Electric Delivery LLC  | No        | The SPS definition should be implemented as soon as possible the way it was originally developed by the NERC System Analysis and Modeling Subcommittee (SAMS) and approved by NERC OC PC. SAMS took several years developing the definition and getting approvals.   |
| <p><b>Response:</b> Thank you for your comment. The drafting team recognizes the efforts of SAMS/SPCS in development of the proposed definition. Several drafting team members participated directly in that process and the drafting team used that report as a starting point in its efforts, but neither NERC nor the drafting team expected this starting point to also be the end point. While the approval of the NERC Operating and Planning Committees is important, it does not rise to the level of stakeholder vetting through the standards development process.</p> |           |  |
| Tri-State Generation and Transmission Association, Inc.  | No        |  |
| Northeast Power Coordinating Council   | Yes       | <ol style="list-style-type: none"> <li>1. The objective to “Meet requirements identified in the NERC Reliability Standards” improperly defines a NERC term by utilizing NERC requirements which can change over time. The purpose of this section is to describe the objectives of an RAS. An RAS is accomplishes the objectives of adequate reliability. Those Standards and requirements that will apply to RAS will list RAS in their requirements.</li> <li>2. The final bullet in an RAS objective “Address other Bulk Electric System (BES) reliability concerns” is open ended. The previous bullets of voltage, stability, flows and Cascade are the hallmarks of adequate levels of reliability.</li> </ol> |

| Organization   | Yes or No | Question 2 Comment   |
|--|-----------|--|
|  |           | <p>3. To the existing definition of Special Protection System (Remedial Action Scheme), after “Such action may include changes in demand, generation (MW and Mvar)...” add the words HVDC power flows, FACTS device operating points,...</p> |
| <p><b>Response:</b> Thank you for your comment.</p> <p>1. The SDT agrees that requirements in NERC reliability Standards can change over time. The statement in the definition does not refer to a specific standard or requirements, nor does it impose requirements by itself. The drafting team considers that meeting requirements in the NERC Reliability Standards is one objective for installing a RAS.</p> <p>2. The drafting team agrees that the item “Address other Bulk Electric System (BES) reliability concerns” is open ended and removed the bullet.</p> <p>3. The drafting team agrees that the proposed additions to the list of RAS actions are legitimate, but declines to make the change because the list provides examples only and is not all-inclusive.</p> |           |  |
| MRO NERC Standards Review Forum  | Yes       |  |
| IRC Standards Review Committee   | Yes       | Reverse Power Sensing Relays should be added to the list of RAS.   |
| <p><b>Response:</b> Thank you for your comment. The drafting team considers reverse power sensing relays to be a protective function. As such, they do not individually constitute a RAS under exclusion “e” which reads: “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service.”</p> <p>However, the drafting team asserts that reverse power sensing relays could, as other protective functions, be part of a larger scheme that meets the definition of RAS.</p>  |           |  |
| SPP Standards Review Group   | Yes       | We have a concern in reference to the term ‘curtailed’ being used in the revised definition. Our thought process associates ‘curtailed’ with the tagging process. The  |

| Organization   | Yes or No | Question 2 Comment   |
|--|-----------|--|
|  |           | group suggests the term ‘reduce’ for it seems more fitting with the terms ‘tripping of generation or load’.  |
| <p><b>Response:</b> Thank you for your comment. The drafting team revised the first sentence of the definition to read: “A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s).”</p>   |           |  |
| City of Vineland   | Yes       | <ol style="list-style-type: none"> <li>1. With the statement in the definition of "but are not limited to", and the first of the inclusions of "Meet requirements identified in the NERC Reliability Standards", there is no real limit on the scope of the definition. Also, the last inclusion "Address other BES reliability concerns" looks like a catchall inclusion that could be applied after the fact. This is not so black and white when talking about a definition of a RAS.</li> <li>2. There needs to be categorization and guidance for the industry to determine their own situations. Not all RAS (in the proposed definition) are equally critical to reliability of the BES.</li> </ol> |
| <p><b>Response:</b> Thank you for your comment.</p> <ol style="list-style-type: none"> <li>1. Because of the diversity of RAS in both action and objective, the practical approach to a definition is to begin with a wide and general scope and then list specific exclusions. However, the drafting team did limit the scope of the objectives by removing the last bullet as you suggested. The revised objectives provide examples and are no longer all-inclusive.</li> <li>2. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.</li> </ol> |           |  |
| ReliabilityFirst   | Yes       | <p>ReliabilityFirst submits the following comments for consideration: 1. Item k. “Automatic sequences that proceed when manually initiated solely by an operator”</p> <ol style="list-style-type: none"> <li>a. ReliabilityFirst is aware of a current RAS for a large generation plant in which the RAS can be armed/de-armed by a system operator. In the cases where this RAS is armed, we would consider this to be a RAS, applicable to any associated NERC</li> </ol>  |

| Organization  | Yes or No | Question 2 Comment   |
|---|-----------|--|
|   |           | <p>Reliability Standards. ReliabilityFirst questions whether it is the intent of item “K” to exclude these types of schemes as a RAS. If so, what is the technical justification/basis for such exclusion?</p> <p>b. The term “operator” is undefined and may be left to interpretation. ReliabilityFirst recommends using the NERC Glossary of Terms definition of “System Operator” to further clarify the term “operator”.</p>  |
| <p><b>Response:</b> Thank you for your comment.</p> <p>a) Exclusion k is not referring to whether schemes are armed by a System Operator or not. A RAS can be armed and waiting on predetermined system conditions to take action. Arming only introduces a layer of supervision and does not determine whether or not a scheme is a RAS. Exclusion k refers to schemes that will take automatic actions upon being initiated manually by a System Operator.</p> <p>b) The drafting team agrees and revised the definition to use the term “System Operator.”</p> |           |  |
| NV Energy   | Yes       | <p>The list of corrective actions taken by a RAS is comprehensive; however, we feel it would be a valuable improvement to clarify that each of the second through fifth bulleted items is applicable only to the BES. For instance, the second bullet would read “Maintain Bulk Electric System stability”; third bullet would read “Maintain acceptable BES voltages”; fourth bullet “Maintain acceptable BES power flows”; and fifth bullet “Limit the impact of Cascading throughout the BES”.</p>  |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives.</p>   |           |  |
| Consumers Energy Company  | Yes       | <p>If the intent was indeed to have this definition apply only to the BES, then we suggest the additional clarifications since many companies may have similar schemes on non-applicable systems: A scheme designed to detect predetermined System conditions on the BES and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives:</p> <ul style="list-style-type: none"> <li>o Meet requirements identified in the NERC Reliability Standards;</li> <li>o Maintain BES System stability;</li> <li>o Maintain acceptable BES System voltages;</li> <li>o</li> </ul> |

| Organization  | Yes or No | Question 2 Comment  |
|---|-----------|---|
|   |           | Maintain acceptable BES power flows; <ul style="list-style-type: none"> <li>o Limit the impact of Cascading on the BES; or</li> <li>o Address other Bulk Electric System (BES) reliability concerns.</li> </ul> |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives. However, the detection of predetermined conditions should not be limited to the BES; therefore, that change was not made.</p> |           |   |
| Colorado Springs Utilities  |           | No Comments   |



**3. Are there additional objectives that should be explicitly included in the proposed definition of RAS? If yes, please provide specific suggestions and rationale.**

**Summary Consideration:**

A majority of commenters agreed there was no need for additional objectives.

Numerous commenters expressed concerns with the first and last stated objectives: respectively, they are “Meet requirements identified in the NERC Reliability Standards” and “Address other Bulk Electric System (BES) reliability concerns”. Commenters questioned whether RAS applications should be limited to meeting requirements of specific NERC Reliability Standards. The drafting team responded that RAS applications should not be limited to meeting requirements and that RAS could be implemented to limit the impact of an extreme event or Cascading. Commenters stated that the last objective was all encompassing making the other objectives irrelevant. In response, the drafting team deleted the objective; thereby, negating the all-inclusive nature of the objective list.

To clarify the intent of the proposed definition of Remedial Action Scheme, numerous commenters also requested that the list of objectives should specifically pertain to the Bulk Electric System (BES). The drafting team agreed and inserted the qualifier “BES” where appropriate.

There were numerous comments unrelated to this question that were addressed but not included in this summary.

| Organization | Yes or No | Question 3 Comment   |
|--------------|-----------|--|
| Dominion     | No        | <ol style="list-style-type: none"> <li data-bbox="779 1040 1892 1305">1. The objectives do not belong in a definition of RAS. These objectives are a restatement of the NERC defined term “Reliable Operation” which is the objective of all Reliability Standards. These are too broad and will cast to wide a net. “Meet the requirements identified in the NERC Reliability Standards” could include standards that are not developed yet. A RAS should only be a RAS if it solves a reliability violation for a specific contingency (not a generic “System condition”) of the type stated in TPL-001-4 or its successor standard.</li> <li data-bbox="779 1312 1787 1419">2. Additionally, we are not sure if it should be a RAS if it only solves “extreme” events in the TPL standards since the label of RAS takes away incentive to mitigate problems.</li> </ol> |

| Organization   | Yes or No | Question 3 Comment |
|--|-----------|--------------------|
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. Because of the diversity of RAS in both action and objective, the practical approach to a definition is to begin with a wide scope and then list specific exclusions. However, the drafting team did limit the scope of the objectives by removing the last bullet. The revised objectives provide examples and are no longer all-inclusive. The objectives serve as examples of why RAS may be installed. The exclusions identify equipment and schemes that should not be considered RAS. The drafting team does not agree that RAS can only be designed to address specific contingencies. RAS may be used to solve either event-based "contingencies" or condition-based "System conditions" (e.g. overloads, etc.).</li> <li>2. The drafting team contends that RAS are not limited to meeting the requirements of the NERC Reliability Standards but may also be implemented for applications such as limiting the impact on the BES of an extreme event or Cascading.</li> </ol> |           |                    |
| FirstEnergy Corp.  | No        |                    |
| Operational Compliance   | No        |                    |
| Duke Energy  | No        |                    |
| Florida Municipal Power Agency   | No        |                    |
| SERC Protection and Controls Subcommittee  | No        |                    |
| IRC Standards Review Committee   | No        |                    |
| Bonneville Power Administration  | No        |                    |

| Organization   | Yes or No | Question 3 Comment  |
|--|-----------|---|
| <p>Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing</p>   | <p>No</p> | <p>The objective "Address other Bulk Electric System (BES) reliability concerns" is too broad. This encompasses every scheme on the system and makes the other objectives irrelevant. This objective should be deleted.</p>   |
| <p><b>Response:</b> Thank you for your comments. The drafting team agrees and revised the objectives by deleting the last bullet that read: "Address other Bulk Electric System (BES) reliability concerns" negating the all-inclusive nature of the objectives.</p>   |           |   |
| <p>SPP Standards Review Group</p>  | <p>No</p> | <p>We would suggest the removal of the first bullet 'Meet requirements identified in the NERC Reliability Standards' from the definition because the RAS shouldn't be implemented in reference to a particular Standard but for the operational needs of the system. Also, we recommend the removal of the last bullet 'Address other Bulk Electric System (BES) reliability concerns' to avoid the lack of clarity that was an issue with the original 'SPS/RAS' definition including it leaves the definition too open to interpretation.</p> |
| <p><b>Response:</b> Thank you for your comments. Because of the diversity of RAS in both action and objective, the practical approach to a definition is to begin with a wide scope and then list specific exclusions. The drafting team did limit the scope of the objectives by removing the last bullet. The revised objectives provide examples and are no longer all-inclusive. The objectives serve as examples of why RAS may be installed. The exclusions identify equipment and schemes that should not be considered RAS. RAS may be used to solve either event-based "contingencies" or condition-based "System conditions" (e.g. overloads, etc.). The SDT maintains that satisfying requirements of a reliability standard is a legitimate RAS objective.</p> |           |   |

| Organization                        | Yes or No | Question 3 Comment  |
|-------------------------------------|-----------|---|
| <p>ACES Standards Collaborators</p> | <p>No</p> | <p>We do not believe any additional objectives are necessary and believe that two objectives should be removed as discussed below.</p> <ol style="list-style-type: none"> <li>1. Use of the term “meet requirements identified in the NERC Reliability Standards” is ambiguous which will lead to inconsistent enforcement. Would this clause apply to any standard or is it intended primarily to apply to TPL standards? Does this require the owner of the RAS to document for which standards the RAS is installed? For a newly installed RAS, this might be easy but there could be disagreement over the purpose of the installation of existing RAS especially those that have been installed for a decade or more. We recommend removing the phrase from the definition. If the phrase persists, please identify specific standards and requirements in the technical guideline section for clarity.</li> <li>2. Use of the term “address other Bulk Electric System (BES) reliability concern” is vague and ambiguous which will only lead to inconsistent enforcement. What other reliability concerns could there be besides system stability, system voltages, power flows, and Cascading that would not be excluded. Protecting equipment from damage would be one reliability concern that does not specifically fit into one of the categories but any schemes associated with protecting equipment from damage would be excluded by exclusion e. or excluded because they are Protection Systems. We simply cannot come up with any additional examples that warrant inclusion of such an ambiguity. We suggest the drafting team remove this phrase to remove the ambiguity. If there are other reliability concerns for which a RAS may be installed that do not fit into one of the five other buckets, then additional specific buckets should be added to avoid ambiguity.</li> <li>3. Because schemes could be interpreted to include AGC and excitation systems, the objectives could also inadvertently result in AGC or excitation systems being classified as RAS. AGC ultimately is required to meet several requirements in the BAL standards and excitation systems are used to control a generator’s reactive power output to maintain an acceptable voltage schedule. Thus, both AGC and excitation systems support at least one of the objectives of the RAS definition.</li> </ol> |

| Organization  | Yes or No | Question 3 Comment   |
|---|-----------|--|
|   |           | These objectives should ultimately be evaluated more closely. At the very least, AGC and excitation systems should be included in the exclusions list. |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team contends that the requested level of specificity regarding the NERC Reliability Standards is not appropriate to include in the RAS definition. It is important that the scope of the definition include schemes whose failure to operate or whose misoperation may pose a reliability risk. Listing specific standards in the definition may unintentionally limit the scope of the definition. The definition by itself imposes no requirements on RAS owners.</li> <li>2. The drafting team agrees and revised the objectives by deleting the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns” negating the all-inclusive nature of the objectives.</li> <li>3. The drafting team agrees that generator controls were not clearly addressed by the exclusion list: therefore, the drafting team added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</li> </ol> |           |  |
| Orlando Utilities Commission  | No        |  |
| Central Lincoln   | No        |  |
| Tacoma Public Utilities   | No        |  |
| CenterPoint Energy  | No        |  |
| Wisconsin Electric Power Company  | No        |  |
| Hydro One   | No        |  |
| ISO New England   | No        |  |
| Pepco Holdings Inc  | No        |  |

| Organization  | Yes or No | Question 3 Comment  |
|---|-----------|---|
| Xcel Energy   | No        |   |
| Manitoba Hydro  | No        |   |
| MidAmerican Energy Company  | No        |   |
| Idaho Power   | No        |   |
| Exelon Companies  | No        |   |
| Nebraska Public Power District  | No        |   |
| ITC   | No        | <p>What purpose does the objectives list serve? Would any scheme be not considered RAS due to its objective? The term “other BES reliability concerns” seems to be all-inclusive so there’s no point to the list.</p> |
| <p><b>Response:</b> Thank you for your comments. Because of the diversity of RAS in both action and objective, the practical approach to the RAS definition is to begin with a wide scope and then list specific exclusions. The drafting team revised the objectives by deleting the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns” negating the all-inclusive nature of the objectives. The objectives serve as examples of why RAS may be installed and are not intended to limit the scope of the RAS definition.</p> |           |   |
| NV Energy   | No        |   |
| Ameren  | No        |   |
| LCRA Transmission Services Corporation  | No        |   |
| PJM Interconnection   | No        |   |

| Organization   | Yes or No | Question 3 Comment  |
|--|-----------|---|
| Independent Electricity System Operator  | No        |   |
| Austin Energy  | No        |   |
| Oncor Electric Delivery LLC  | No        |   |
| Tri-State Generation and Transmission Association, Inc.  | No        |   |
| Northeast Power Coordinating Council   | Yes       | <ol style="list-style-type: none"> <li>1. It is not clear why "unanticipated" was omitted from the first sentence of the definition. While it is true that at least in WECC most of the conditions its RASs detect are predetermined, in other regions that might not be the case and omission of the term creates a loophole that is not there now. A RAS is designed to respond to System Conditions that could happen. The schemes are developed in response to Planning Studies. Protection systems are not installed without considering the conditions that will activate them.</li> <li>2. First bullet: Have SPS/RAS requirements literally been identified in NERC standards, or is the intent that the SPS/RAS be applied so that the power system meets the performance requirements identified in the NERC reliability standards?</li> <li>3. Sixth bullet: What is a reliability "concern"? Wouldn't it be more accurate to say address other conditions that could otherwise result in failure to comply with reliability standards?</li> </ol> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team contends that the system conditions being detected by the RAS must be predetermined in order to define operation of the RAS. Events which could lead to such conditions, however, may be "unanticipated" events specific or contingencies. The proposed definition encompasses both event and condition scenarios.</li> </ol> |           |   |

| Organization  | Yes or No | Question 3 Comment   |
|---|-----------|--|
|   |           | <p>2. No, SPS/RAS have not been literally identified in NERC standards. NERC Reliability Standards specify reliability objectives (outcomes) and do not specify the “how” or the methods used to achieve the objectives. Installing a RAS is one possible method to address the reliability objective of a standard.</p> <p>3. The drafting team removed the last objective that read: “Address other Bulk Electric System (BES) reliability concerns” as many commenters stated it was all-encompassing.</p>  |
| MRO NERC Standards Review Forum   | Yes       | <p>The definition as drafted includes use of Bulk Electric System in some places and not in others. Assuming the RAS that are covered under this standard are only those in the BES, the following changes are suggested to clarify this: A scheme designed to detect predetermined Bulk Electric System (BES) conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping BES generation or other BES sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives:</p> <ul style="list-style-type: none"> <li>o Meet requirements identified in the NERC Reliability Standards;</li> <li>o Maintain BES stability;</li> <li>o Maintain acceptable BES voltages;</li> <li>o Maintain acceptable BES power flows;</li> <li>o Limit the impact of BES Cascading; or</li> <li>o Address other BES reliability concerns</li> </ul> <p>To eliminate any doubt that the text used in NERC Reliability Standards properly applies to only BES Remedial Action Schemes. The NSRF recommends establishing a RAS Definition that applies explicitly to the BES. This objective could be accomplished by defining it as a “BES Remedial Action Scheme” and replacing the references to “System” with “BES”. The existing references in the proposed RAS Definition to “System or Systems” apply more broadly to non-BES transmission systems and distribution systems.</p> |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives. However, the detection of predetermined conditions should not be limited to the BES; therefore, that change was not made.</p> |           |  |
| National Grid   | Yes       | <p>RE: "RAS accomplish one or more of the following objectives: Maintain System Stability" Can a RAS/SPS maintain system stability or does it prevent (or at least lessen the odds of) system instability?</p>   |



| Organization   | Yes or No | Question 3 Comment  |
|--|-----------|---|
| <p><b>Response:</b> Thank you for your comments. The drafting team inserted “BES” as a qualifier in the pertinent objectives. The drafting team contends that maintaining Bulk Electric System (BES) stability is synonymous with preventing System instability.</p>   |           |   |
| Tennessee Valley Authority   | Yes       | <p>The bulleted list of objectives fails to enhance clarity, and could in fact increase the uncertainty around RAS. Bullets 2-6 can be interpreted to cover objectives beyond NERC Reliability Standards, when taken in context with the first bullet. The scope of the definition should be limited to applications that are relevant to the NERC Reliability Standards in which the term is used. See proposed modifications under question 1 response.</p> |
| <p><b>Response:</b> Thank you for your comments.</p> <p>Because of the diversity of RAS in both action and objective, the practical approach to the RAS definition is to begin with a wide scope and then list specific exclusions. However, the drafting team did limit the scope of the objectives by removing the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns.” The revised objectives provide examples and are no longer all-inclusive. The objectives serve as examples of why RAS may be installed. The exclusions identify equipment and schemes that should not be considered RAS. RAS may be used to solve either event-based "contingencies" or condition-based "System conditions" (e.g. overloads, etc.). The SDT maintains that satisfying requirements of a reliability standard is a legitimate RAS objective. The drafting team does not agree that RAS should be limited to applications that are relevant to the NERC Reliability Standards in which the term is used. RAS may also be implemented for applications beyond requirements of the NERC Reliability Standards, such as to limit the impact of an extreme event or Cascading.</p> |           |   |
| PacifiCorp   | Yes       | <p>To clarify the intent of the proposed definition of Remedial Action Scheme, PacifiCorp recommends inserting Bulk Electric System into the first sentence as follows: “A scheme designed to detect predetermined Bulk Electric System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s).”</p>    |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives. However, the detection of predetermined conditions should not be limited to the BES; therefore, that change was not made.</p>  |           |   |

| Organization   | Yes or No | Question 3 Comment  |
|--|-----------|---|
| City of Vineland   | Yes       | Categorization of RAS for criticality.  |
| <p><b>Response:</b> Thank you for your comments. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.</p>   |           |   |
| Ingleside Cogeneration LP  | Yes       | <p>The exclusions proposed by the drafting team are comprehensive and precise - and the bulleted list of “inclusions” under the base definition of RAS must be as well. In the original definition, such descriptors included those RAS whose loss or malfunction would lead to “Non-Consequential Load Loss ≥ 300 MW”, “Aggregate resource loss (tripping or runback of generation or HVdc) &gt; the largest Real Power resource within the interconnection”, “Loss of synchronism between two or more portions of the system each including more than one generating plant”, and “Negatively damped oscillations”. ICLP is not sure why specifics like this were removed to begin with - and we believe it is the responsibility of the drafting team to provide the rationale, not the industry.</p> |
| <p><b>Response:</b> Thank you for your comments. The SAMS-SPCS whitepaper does include specifics on suggested classifications. However, the classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. Please see the FAQ document.</p> |           |   |
| American Transmission Company, LLC   | Yes       | <p>To eliminate any doubt that the text used in NERC Reliability Standards properly applies to only BES Remedial Action Schemes, ATC recommends establishing a RAS Definition that applies explicitly to the BES. This could be accomplished by defining it as a “BES Remedial Action Scheme” and replacing the references to “System” with “BES.” The existing references in the proposed RAS Definition to “System” or “Systems” apply more broadly to non-BES transmission systems and distribution systems.</p>   |

| Organization  | Yes or No | Question 3 Comment  |
|---|-----------|---|
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives. However, the detection of predetermined conditions should not be limited to the BES; therefore, that change was not made.</p> |           |   |
| Omaha Public Power District   | Yes       | An objective of this project is to create a RAS definition and to eliminate the need for an SPS definition. Somewhere, that should be clarified.  |
| <p><b>Response:</b> Thank you for your comment. Please see the FAQ document.</p>  |           |   |
| Consumers Energy Company  | Yes       | <p>If the intent was indeed to have a broader definition and then restrict its applicability when used in each standard, then we suggest the following clarifications: A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a System(s). RAS accomplish one or more of the following objectives:</p> <ul style="list-style-type: none"> <li>o Meet requirements identified in the NERC Reliability Standards;</li> <li>o Maintain System stability;</li> <li>o Maintain acceptable System voltages;</li> <li>o Maintain acceptable power flows;</li> <li>o Limit the impact of Cascading; or</li> <li>o Address other Bulk Electric System (BES) reliability concerns.</li> </ul> <p>Then each standard using this term would state something like “...an RAS used to address BES reliability...” to help define applicability in each standard.</p> |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives.</p>   |           |   |
| Colorado Springs Utilities  |           | No Comments   |

#### 4. Do you agree with the exclusion list in the proposed definition of RAS? If not, please provide specific suggestions and rationale.

##### Summary Consideration:

Approximately 40% of commenters agreed with the proposed exclusion list. There were three primary themes in the comments submitted by stakeholders that disagreed.

##### 1. Include an exclusion for Protection Systems that clear Faults

In response, the drafting team added a new exclusion (a) which reads: “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements.

##### 2. Include an exclusion for AGC and other generator excitation systems

In response, the drafting team added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing”.

##### 3. Requested clarity of the UVLS exclusion

In response, the drafting team combined the posted exclusions (b) UFLS and (c) UVLS into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program.”

A few commenters requested an exclusion for switching performed in the same station (including transfer- or cross-trip schemes) that trip Elements other than the impacted Element.

The drafting team thought this concept was too broad and contends that schemes that reconfigure the System should be RAS. No change made.

Other commenters requested additional examples be included several of the exclusions.

The drafting team declined to make the suggested changes noting that they were not attempting to provide an all-inclusive list of examples.

A few commenters questioned the general formatting of the definition and the need for an exclusion list.

The drafting team explained the definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS

could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS. Note, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety.

There were numerous comments unrelated to this question that were addressed but not included in this summary.

| Organization   | Yes or No | Question 4 Comment   |
|--|-----------|--|
| Northeast Power Coordinating Council   | No        | <ol style="list-style-type: none"> <li>1. Regarding Item “c” (Undervoltage Load Shedding Programs [UVLS Programs]) of what does not individually constitute a RAS, UVLS Program must become an approved definition. Local undervoltage load shedding schemes that are not installed “to mitigate the risk of Cascading, voltage instability, voltage collapse, or uncontrolled separation resulting from undervoltage conditions” as defined in the draft PRC-010-1 should be excluded, therefore, “c. Undervoltage load Shedding Programs (UVLS Programs)” should be changed to “c. Automatic undervoltage load shedding schemes, including UVLS Programs. However, centrally controlled dispersed undervoltage load shedding schemes are RAS.” An objective could be added to address centrally controlled Remedial Action Schemes.</li> <li>2. After the bulleted section, the sentence “The following do not individually constitute an RAS” could be read as implying that two or three of them taken together might constitute an RAS, which may or may not be the case. Suggest revising to read “The following do not individually, or combined in part or total, constitute a RAS.”</li> <li>3. Please list UFLS and UVLS programs with the same capital letters and use of parentheses.</li> </ol> |
| <p><b>Response:</b> Thank you for your comment.</p> <ol style="list-style-type: none"> <li>1. The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program” definition.</li> </ol> |           |  |

| Organization   | Yes or No | Question 4 Comment   |
|--|-----------|--|
| <p>2. The drafting team contends that two or more exclusions taken together may or may not constitute a RAS. Individually, an exclusion is not a RAS; however, any of the exclusion(s) could be an integral part of a larger scheme that meets the RAS definition.</p> <p>3. The drafting team followed the NERC style guide for capitalization.</p>   |           |  |
| <p>Colorado Springs Utilities</p>  | <p>No</p> | <p>1. Colorado Springs Utilities does not agree with the exclusion list in the proposed definition. We do not think that it is reasonable or prudent to create a comprehensive list of exclusions. There will always be just one more exception that will force us to continue to modify the list of exclusions. Also, if it is not explicitly defined as an exception then by default it is automatically included whether it could affect reliability or not. The definition should clearly define what a RAS so as to include those schemes identified as essential to reliability. The only implicit exclusion we would recommend would be to exclude protection schemes that meet the definition of a RAS and are explicitly covered under other NERC reliability standards. Utilities would then use the definition to make sure that essential protection systems that meet the definition are included and document any further assumptions or judgement used in delineating between RAS and non-RAS schemes. Trying to micro-manage every possible exclusion or inclusion we think is not realistic and should not be necessary. If we do keep the exclusions list then we would offer the following suggestions on the current list of exclusions, and would anticipate a fairly steady flow of additions/modifications to this list moving forward.</p> <p>2. Remove “automatic” from UFLS.</p> <p>3. Should we explicitly exclude GMD responses? Refer to EOP-010-1/TPL-007-1.</p> |
| <p><b>Response:</b> Thank you for your comment.</p> <p>1. The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS. Note, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety.</p> |           |  |

| Organization  | Yes or No | Question 4 Comment   |
|---|-----------|--|
| <p>2. The drafting team disagrees and declined to make the suggested change.</p> <p>3. The drafting team contends that most GMD responses are equipment-based protection and would be covered by exclusion (e).</p>   |           |  |
| <p>MRO NERC Standards Review Forum</p>  | <p>No</p> | <p>1. The NSRF suggests: Item c - Consider rewording to better show the correlation to Item b by including the adjective 'automatic', with text like, "Automatic Undervoltage Load Shedding Programs (UVLS Programs)</p> <p>2. Item f - consider adding ". . . and controllers that . . ." to the middle of the item for improved readability.</p> <p>3. Item h - Consider using wording more aligned with Item g, such as ". . . remotely switch static shunt reactive devices for voltage regulation . . .". Otherwise consider wording like, "remotely switch static shunt inductors or static shunt capacitors for voltage regulation . . .".</p>  |
| <p><b>Response:</b> Thank you for your comment.</p> <p>1. The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: "Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays." The drafting team tailored this exclusion to match the language of the recently-approved "UVLS Program" definition.</p> <p>2. The drafting team disagrees and declined to make the suggested change.</p> <p>3. The drafting team disagrees and declined to make the suggested change.</p> |           |  |
| <p>Dominion</p>   | <p>No</p> | <p>From item "f", strike the term "and that are located at and monitor quantities solely at the same station as the Element being switched or regulated." Why does it make a difference whether the controller is local or remote? The advent of high-speed phase measurement units (PMUs) and faster computer systems will eventually allow wide area control. This will become essential as the customer's load characteristic evolves (less voltage and frequency dependency means local PSSs will be less effective). We are concerned that the definition in general will hamper innovation. Right now there are schemes that control LTC's and capacitors to minimize losses. Certainly these are not RAS. There are EMS controls such as what PJM uses that dispatch generation precontingency to avoid</p> |

| Organization  | Yes or No | Question 4 Comment   |
|---|-----------|--|
|   |           | <p>overloads/voltage problems. These are not RAS either. Eventually computer EMS systems will become fast and robust enough to drop load or reconfigure the system so quickly that wide area blackouts will be virtually eliminated. Recall that only 500 MWs of load drop would have stopped the 2003 blackout. Therefore wide area systems that generically react to problems (not designed for a single specific contingency (if line A opens, do xyz action)) should not be RAS.</p>   |
| <p><b>Response:</b> Thank you for your comment. The difference between local and remote control is the associated increase of reliability risk. Schemes that act remotely are more likely to have a broad impact on the System and merit the more rigorous oversight required for RAS. For your examples: the drafting team agrees that schemes that control LTC's and capacitors to minimize losses are typically not RAS; EMS controls for generation dispatch are typically not RAS; however, "wide area systems that generically react to problems" by dropping load or reconfiguring the System are typically RAS.</p> |           |  |
| Seattle City Light  | No        | <p>Seattle appreciates the efforts of the drafting team to be complete, but has concern with a definition that is primarily a negative definition, i.e. a definition of what a RAS is NOT. If such an approach is deemed the most practical, Seattle recommends that a general item be added to the list of what a RAS is not, such as "n. any other scheme that does not automatically act to maintain System performance or BES reliability on a wide area." The point is to have a general item that entities or auditors could point to, in the likely case that additional non-RAS schemes are identified that do not fall within the 13 "these are not a RAS" items identified so far.</p> |
| <p><b>Response:</b> Thank you for your comment. Because of the diversity of RAS in both action and objective, the practical approach to a definition is to begin with a wide scope and then list specific exclusions. The exclusions identify equipment and schemes that should not be considered RAS. RAS may be used to solve either event-based "contingencies" or condition-based "System conditions" (e.g. overloads, etc.). The drafting team declines to make the suggested change because the proposed exclusion is too broad.</p>  |           |  |
| Operational Compliance  | No        | <p>Part c. of Exclusions lists "Undervoltage Load Shedding Programs (UVLS Programs)". The definition of "UVLS Programs" needs to be clarified up front in the same space as the RAS definition. 1. The distinction between "centrally controlled UVLS" being included as part of the RAS definition and "locally controlled UVLS" not included in</p>  |



| Organization  | Yes or No | Question 4 Comment  |
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|   |           | <p>RAS Definition should be reclarified here. 2. The distinction between UVLS Program schemes and UVLS schemes that are not part of the entity “UVLS Program” also needs to be spelled out. For one intimately familiar with NERC standards, the information is available, but items 1. and 2. should be clear for a reader with somewhat limited knowledge of other standards. For example, engineers need to follow the NERC standards in their work, but may not be intimately familiar with other NERC standards, guidelines and definitions.</p> |
| <p><b>Response:</b> Thank you for your comment. The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program” definition.</p> |           |   |
| <p>Florida Municipal Power Agency</p>   | <p>No</p> | <p>The RAS definition is too broad as drafted and should specifically exclude control systems such as AGC, AVR, governor controls, etc. Suggested language is provided under number 1.</p>  |
| <p><b>Response:</b> Thank you for your comment. The drafting team acknowledges this needed addition and added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</p>   |           |   |
| <p>Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing</p>  | <p>No</p> | <p>Additional words should be added to Exclusion e as follows: "Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by 1) removing it from service or 2) performing switching in the same substation as the Element to relieve the condition.</p>  |

| Organization  | Yes or No | Question 4 Comment   |
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| <p><b>Response:</b> Thank you for your comment. The drafting team contends that “performing switching in the same substation as the Element to relieve the condition” is too broad of an exclusion. Schemes that reconfigure the System should be RAS.</p>  |           |  |
| SPP Standards Review Group  | No        | <p>The distinction between distributed and central controlled UVLS systems is not clear in the definition. The clarification is contained in the supporting documentation for the definition but requires extensive efforts to dig it out. We suggest the drafting team revise exclusion C in the proposed definition to provide more clarity.</p>   |
| <p><b>Response:</b> Thank you for your comment. The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program” definition.</p> |           |  |
| PacifiCorp  | No        | <p>The proposed RAS definition will result in a significant expansion of the number of schemes that meet the criteria for classification as a RAS. In many instances, this expansion will not result in an improvement in Bulk Electric System reliability, and will unnecessarily complicate analysis of transmission system reliability.</p> <p>PacifiCorp recommends that the drafting team consider expansion of the exclusion list to include transfer- or cross-trip schemes that are located within a single substation. This exclusion would encompass schemes that operate from relays contained within substation apparatus to trip additional system elements other than those that are directly monitored by the relays with no additional logic or communications. As these schemes may be modeled with simple contingency definitions, PacifiCorp does not believe that their inclusion in the definition of RAS will provide any additional benefit for system reliability purposes. As stated in previous comments submitted to the drafting team by PacifiCorp on April 9, 2014, many common protection schemes that utilize breaker status contacts or lockout contacts to transfer trip multiple elements within a substation will meet the new SPS definition, despite limited potential impacts to the Bulk Electric System. For example, consider a scheme that utilizes a status contact on a line breaker to transfer-trip a</p> |

| Organization  | Yes or No | Question 4 Comment  |
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|   |           | <p>shunt capacitor within the substation in conjunction with line tripping. In this example, the scheme is contained within the substation, and does not utilize any arming logic. The intent of the example scheme is to provide fast shunt device tripping and to provide additional redundancy for the shunt device voltage control. Under the draft definition, this scheme would meet the RAS criteria, as the shunt capacitor control is not based on locally-sensed voltage and system elements are tripped for a reason other than facilitation of fault clearing. Tripping of the capacitor could easily be modeled with a single line of code in a contingency definition, with the same results for system analysis and reliability purposes as inclusion in RAS databases. As such, this scheme and similar schemes that cross-trip various system elements within a single substation should have a specific exclusion in the proposed RAS definition. In addition, PacifiCorp recommends one specific change to the list of RAS exclusions. Exclusion “e” should include an Element in series as follows: “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element or series Element against damage by removing it from service.” It may be simpler and less costly to remove an Element in series with the overloaded Element rather than the overloaded Element itself.</p> |
| <p><b>Response:</b> Thank you for your comment. The drafting team contends that performing switching in the same substation (including transfer- or cross-trip schemes) that trip Elements other than the impacted Element is too broad of an exclusion. Schemes that reconfigure the System should be RAS.</p> |           |   |
| Orlando Utilities Commission  | No        | <p>It is not clear what the status is of an RAS type system on nonBES facilities. For example a system that if installed at 230 kV would clearly be RAS, but is installed below 100kv. A system that only operates and protects nonBES facilities.</p>  |
| <p><b>Response:</b> Thank you for your comment. To clarify, the drafting team inserted “BES” as a qualifier in the pertinent objectives.</p>  |           |   |
| Central Lincoln   | No        | <p>Central Lincoln proposes the following be excluded: “Automatic transfer or system reconfiguration schemes intended to limit the extent and/or duration of outages; and not intended to benefit the BES.” These systems operate similar to reclosing, in that</p>   |

| Organization   | Yes or No | Question 4 Comment  |
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|  |           | <p>they are intended to restore power quickly. Unlike reclosing, they may restore the power via an alternate path. We note the radial systems likely to benefit from auto-reconfiguration of load are unlikely to meet the BES definition, but the proposed definition of RAS has little dependency on the BES definition. The third RAS inclusion (Maintain acceptable System voltages) might be interpreted to include the auto-reconfiguration of load described above.</p>  |
| <p><b>Response:</b> Thank you for your comment. The drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) “Automatic Reclosing schemes;” however, system reconfiguration schemes that transfer the load to another source typically would be a RAS.</p> |           |   |
| Tacoma Public Utilities  | No        | <ol style="list-style-type: none"> <li>1. Tacoma Power supports FMPA’s comments concerning Question 4.</li> <li>2. Furthermore, additional clarification seems necessary for (e): “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service.” Perhaps there could be another category for backing-up operator response and re-dispatch: “Locally sensing devices intended to mitigate thermal damage, within expected system re-dispatch response times, such as 10 minutes or greater. Examples are cooling fans, oil pumps, or thermal protection systems.”</li> <li>3. Does the phrase “power system stabilizers” need to be explicitly added to (f)?</li> <li>4. In the FAQ document, on page 5 of 8, under “Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open,” include something like the following two examples: (1) Opening the remote terminal(s) to remove an overload on the line in question following operation of the local terminal when there was no fault on the line in question and (2) opening the remote terminal(s) as a precaution against inadvertently closing back into a local island with generation.</li> </ol> |
| <p><b>Response:</b> Thank you for your comment.</p>  |           |   |

| Organization  | Yes or No | Question 4 Comment   |
|---|-----------|--|
|   |           | <ol style="list-style-type: none"> <li>1. The drafting team acknowledges this needed addition and has added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</li> <li>2. The drafting team did not try to create an exhaustive list of examples.</li> <li>3. The drafting team acknowledges this needed addition and has added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</li> <li>4. The drafting team did not try to create an exhaustive list of examples.</li> </ol>   |
| Wisconsin Electric Power Company  | No        | <ol style="list-style-type: none"> <li>1. We recommend the following changes to the exclusions list a) through i), by item:e.) To simply include generator loss of field ignores many other generator protections for abnormal operating conditions. Revise this exclusions list to add the following: “Generator abnormal operating conditions listed in IEEE C37.102.” (Or, list each individually, that is, “loss of field, unbalanced currents, loss of synchronism, overexcitation, motoring, over/under-voltage, and abnormal frequencies.”)</li> <li>2. f.) This exclusion needs clarification. Does the clause “controllers that switch or regulate...” apply only to “series or shunt reactive devices”, or does it extend to the rest of the items in this list? We suggest that the term “switch or regulate” creates ambiguity. We suggest simply using the term “controls “. Any controls for the various equipment listed should be excluded from being RAS. We also suggest that generator turbine controls be added to this list.</li> <li>3. j.) We propose that the SDT add a new item after item i), to include “Schemes that automatically shutdown a generator upon load rejection.”</li> </ol> |
| <p><b>Response:</b> Thank you for your comment.</p> <ol style="list-style-type: none"> <li>1. The drafting team did not try to create an exhaustive list of examples.</li> <li>2. The drafting team removed generator excitation from exclusion (f) and created a new exclusion (n) to address your concern.</li> </ol> |           |  |

| Organization  | Yes or No | Question 4 Comment  |
|---|-----------|---|
| <p>3. The drafting team asserts that, regardless of the scheme used to originally remove the generator from service (RAS or not), once the generator is disconnected from the System, the reasons for any subsequent automatic shutdown actions would not be a RAS and not subject to RAS oversight.</p>  |           |   |
| City of Vineland  | No        | Problems with determining a UVLS Program and RAS.   |
| <p><b>Response:</b> Thank you for your comment. The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program” definition.</p> |           |   |
| Hydro One   | No        | Local undervoltage load shedding schemes should be excluded, therefore, in the exclusion list, “c. Undervoltage load Shedding Programs (UVLS Programs)” should be changed to “c. Automatic undervoltage load shedding schemes, including UVLS Programs. However, centrally-controlled dispersed undervoltage load shedding schemes are RAS.”  |
| <p><b>Response:</b> Thank you for your comment. The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program” definition.</p> |           |   |
| ISO New England   | No        | <ol style="list-style-type: none"> <li>1. Exclusion “e.” is too broad. There are instances where an overcurrent device that opens a line should be considered a RAS. As currently written, these schemes would fall under exclusion “e.” and would no longer be considered RAS.</li> <li>2. Exclusion “j.” should be limited depending on the size of the island, as determined by the Reliability Coordinator. For example, in some areas 800 MW may be small for a single dedicated facility, but in other areas, an 800 MW island could be substantial.</li> <li>3. Exclusion “m.” should be limited to SSR protection schemes that act solely at the same station. It should read: “Sub-synchronous resonance (SSR) protection schemes that directly detect and act solely at the same station depending on sub-synchronous quantities (e.g. currents or torsional oscillations).”</li> </ol> |

| Organization  | Yes or No | Question 4 Comment   |
|---|-----------|--|
|   |           | <p>4. Another exclusion (“n.”) should be added to exclude schemes that are specifically designed to restore load (often called load throw-over schemes) so that they are not considered RAS. An example of this is a 115-kV line that has load tapped off the middle. After a fault on the line, switches automatically open up at the tapped station and each end of the 115 kV line tries to pick up the load. The unfaulted end of the line will restore the load, and the faulted end will trip out and remain open. However, we do not believe that schemes which are taking actions such as automatic network reconfiguration to reenergize equipment that was tripped as a result of fault clearing which is not restoring load should be excluded.</p> |
| <p><b>Response:</b> Thank you for your comment.</p> <ol style="list-style-type: none"> <li>The list of exclusions in the RAS definition is prefaced by the statement: “The following do not individually constitute a RAS.” The drafting team contends that an overcurrent device applied to a single Element would usually not be a RAS.</li> <li>The drafting team contends the MW size of the island is inconsequential with regards to the definition of a RAS.</li> <li>Exclusion (m) is consistent with present industry practices and the drafting team declined to make the suggested change. The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.</li> <li>The drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) “Automatic Reclosing schemes;” however, system reconfiguration which transfers the load to another source typically would be a RAS.</li> </ol> |           |  |
| Ingleside Cogeneration LP   | No        | <p>If the core definition is not modified as ICLP proposes in response to Question 1, we believe that an exclusion must be made for a protective scheme that takes corrective action “other than the isolation of faulted elements”. Without it, a relay owner will have to demonstrate to a CEA that they individually considered almost every relay system before determining that it is not a RAS. If there are such systems that isolate faulted elements and need RAS-like oversight, they can be explicitly listed under the core definition.</p>  |

| Organization  | Yes or No | Question 4 Comment  |
|---|-----------|---|
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and added a new exclusion (a) which reads: Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements. The drafting team also added clarifying language in the FAQ.</p> |           |   |
| <p>Manitoba Hydro</p>   | <p>No</p> | <ol style="list-style-type: none"> <li>1. In the exclusion list a), it is not necessary to include power swing blocking.</li> <li>2. In the exclusion list e), it is not clear what “high voltage” here is intended to mean, does it mean overvoltage protection? Consider revise this as: “Schemes applied on an Element that react to non-Fault conditions, such as, but not limited to, generator loss-of-field protection, transformer top-oil temperature monitoring and protection, overvoltage protection, or overload protection to protect the Element itself against damage by removing it from service”</li> <li>3. In exclusion list f), “switch or regulate” needs clarification, for example, what does “switch or regulate generation excitation” mean? Is converting a unit from a generator to a synchronous condenser considered as switching of generation excitation?</li> <li>4. Also, “at the same station” needs clarification. For example, if a generator switching station is less than 1 km away from its generating station, can they be considered as the same station?</li> <li>5. The exclusion list covers transmission elements very well. One special transmission element missing is a braking resistor. Is use of a braking resistor a RAS or a permissible element used to maintain stability? Braking resistors are somewhat uncommon and could fall under the RAS definition.</li> <li>6. One special generator feature could be included in the exclusion list - fast valving. Fast valving is a common method used in steam turbines to improve stability and avoid generator tripping.</li> </ol> |
| <p><b>Response:</b> Thank you for your comment.</p>   |           |   |



| Organization  | Yes or No | Question 4 Comment  |
|---|-----------|---|
|   |           | <ol style="list-style-type: none"> <li>1. The existing NERC Glossary of Terms definition of SPS or RAS excludes out-of-step relaying because it is a protective function. The SDT maintained the exclusion but changed the wording from “out-of-step relaying” to “out-of-step tripping and power swing blocking” to reflect current industry terminology.</li> <li>2. The drafting team made the suggested change to “overvoltage.”</li> <li>3. The drafting team removed generator excitation from exclusion (f) and created a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</li> <li>4. The drafting team contends that if the generating station and the switching station share infrastructure such as the same ground grid, then they could be considered to be the same station.</li> <li>5. The drafting team contends that a braking resistor would typically be a component of a RAS.</li> <li>6. Fast valving is included in the new exclusion (n).</li> </ol> |
| MidAmerican Energy Company  | No        | Exception "e" could be read to only include schemes that take the action of removing an element from service. If an action does something other than removing an element from service but its objective is to protect the element it should be included in this exception. Suggest removing the words "by removing it from service" be deleted from this exception.   |
| <p><b>Response:</b> Thank you for your comment. The SDT contends that switching in the same substation other than the impacted Element is too broad of an exclusion. Schemes that reconfigure the System should be RAS.</p> |           |   |
| Exelon Companies  | No        | Exception “c” of the proposed definition of RAS excludes “UVLS Programs”. The background information provided in the FAQ document suggests that the intent of using the term “UVLS Program” in this exclusion was to exclude UVLS schemes that are not centrally controlled. The Project 2008-02 Undervoltage Load Shedding drafting team states in their June 24, 2014 FAQ that UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators but not required by the planners do not meet the attributes of the proposed defined term “UVLS Program” and are therefore not subject to the requirements of PRCâ€™010â€™1. This raises uncertainty as to whether such schemes, even if not centrally-controlled, are RAS, UVLS Programs, or neither. Please clarify whether  |

| Organization  | Yes or No | Question 4 Comment   |
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|   |           | <p>exception “c” of the proposed definition of RAS would include a non-centrally-controlled UVLS scheme owned by a Transmission Owner, Distribution Provider, or Transmission Operator but not required by the Planning Coordinator or Transmission Planner, which is therefore not covered by the Project 2008-02 revisions to PRC-010. Exelon contends that such a scheme should not be considered a RAS.</p>  |
| <p><b>Response:</b> Thank you for your comment. The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program” definition.</p>   |           |  |
| <p>American Electric Power</p>  | <p>No</p> | <p>Once again, AEP believes the drafting team has done well in developing their exclusions list. As stated previously however, AEP believes it is unclear from the proposed definition and associated exclusions list whether automatic load rejection (ALR) of a generating unit is considered to be a Remedial Action Scheme. AEP believes that ALR is not an RAS and should be explicitly excluded in definition to avoid confusion.</p>  |
| <p><b>Response:</b> Thank you for your comment. An automatic load rejection scheme (ALR) may or may not be a RAS depending upon the application details.</p>  |           |  |
| <p>Omaha Public Power District</p>  | <p>No</p> | <p>The Omaha Public Power District (OPPD) believes that the exclusion list needs to be further clarified to state that the EMS/SCADA related schemes are not part of the RAS. Currently, this concern is addressed in the associated FAQ document; however, this document is not going to be part of the RAS Definition going forward. OPPD is concerned that lack of this clarity in the definition may cause inadvertent inclusion of schemes/systems that traditionally are not identified as RAS or SPS.</p> |
| <p><b>Response:</b> Thank you for your comment. The drafting team acknowledge that the EMS/SCADA can be a component of a RAS as described in the FAQ which reads: “The above-mentioned control systems support and enable grid operations by issuing control commands mostly to geographically distributed power System devices. In this normal application, e.g. automatic generation control (AGC), these systems are not considered to be RAS. However, if these systems are configured to detect predetermined conditions</p> |           |  |

| Organization  | Yes or No | Question 4 Comment   |
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| <p>and take corrective actions consistent with the RAS definition, these automatic functions (not the entire EMS) would be considered to be part of a RAS. The identification of RAS is not dependent upon the specific hardware or platform utilized in the scheme. For example, an automatic UVLS scheme centrally controlled through an EMS would be a RAS.” The FAQ will remain as part of the documentation associated with the development of the RAS definition.</p>   |           |  |
| NRECA   | No        | <p>Although NRECA does not believe that Automatic Generation Control (AGC) is a Remedial Action Scheme (RAS), the definition of AGC includes “automatically adjusts generation” which for some NRECA members is implied in the “curtailing generation” language included in the RAS definition. For clarity, consider including AGC in the list of exclusions.</p>   |
| <p><b>Response:</b> Thank you for your comment. The drafting team acknowledges this needed addition and has added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</p>   |           |  |
| LCRA Transmission Services Corporation  | No        | <ol style="list-style-type: none"> <li>1. LCRA TSC recommends an additional example be included under the heading “The following do not individually constitute a RAS:” stated, “Protection systems installed to clear faults.”</li> <li>2. It appears that items F and G of the proposed definition are in conflict. Item G creates an exclusion that is taken away in item F for FACTS devices but leaves in place the limitation for switched shunts. LCRA TSC recommends revising items f. and g. as follows: f. Controllers that switch or regulate series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, tap-changing transformers, or generation excitation.</li> </ol> |
| <p><b>Response:</b> Thank you for your comment.</p> <ol style="list-style-type: none"> <li>1. The drafting team agrees and added a new exclusion (a) which reads: Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements. The drafting team also added clarifying language in the FAQ.</li> <li>2. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations.</li> </ol> |           |  |

| Organization  | Yes or No | Question 4 Comment   |
|---|-----------|--|
| Consumers Energy Company  | No        | We recommend that the first more restrictive definition that applies only to the BES be adopted. If this were done, then we would vote affirmative for this definition.  |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and inserted “BES” as a qualifier in the pertinent objectives. The drafting team further revised the objectives by deleting the last bullet that read: “Address other Bulk Electric System (BES) reliability concerns” negating the all-inclusive nature of the objectives.</p>                            |           |  |
| Austin Energy   | No        | The RAS definition is too broad as drafted and should specifically exclude control systems such as AGC, AVR, governor controls, etc. Suggested language is provided under number 1.  |
| <p><b>Response:</b> Thank you for your comment. The drafting team acknowledges this needed addition and has added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</p> |           |  |
| Tri-State Generation and Transmission Association, Inc.   | No        | Although Tri-State does not believe that Automatic Generation Control (AGC) is a Remedial Action Scheme (RAS), the definition of AGC includes “automatically adjusts generation” which for some may be implied in the “curtailing generation” language included in the RAS definition. For clarity, consider including AGC in the list of exclusions |
| <p><b>Response:</b> Thank you for your comment. The drafting team acknowledges this needed addition and has added a new exclusion (n) which reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing.”</p> |           |  |
| FirstEnergy Corp.   | Yes       | Exclusion "e", Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage, or overload to protect the Element against damage by removing it from service. Please provide clarification on this exclusion.   |
| <p><b>Response:</b> Thank you for your comment. The drafting team contends these schemes are protective functions applied on an Element to protect it from damage, and as such, are not RAS.</p>  |           |  |

| Organization  | Yes or No | Question 4 Comment  |
|---|-----------|---|
| Tennessee Valley Authority  | Yes       | We think it’s appropriate to address exclusions, however when the exclusion list is this long (and perhaps growing) it highlights the challenge in developing a good base definition for what constitutes a RAS NERC-wide. An alternative would be to “catalog” the RAS exclusions in a separate NERC reference document that could be revised without revising the base RAS definition.  |
| <p><b>Response:</b> Thank you for your comment. The drafting team declines to make the suggested change because having separate documents is more cumbersome.</p>   |           |   |
| Duke Energy   | Yes       | Duke Energy does agree with the exclusion list, however, we request clarification on exclusion “a. Out of step tripping and power swing blocking.” Does the exclusion apply when transfer trips and supervisory signals are used as an integral part of the Out of step tripping (OST) and power swing blocking (PSB) functions? It is possible to have an OST or a PSB and transfer a trip to many locations as part of that signal. It is also possible to have supervisory signals such as Voltage to enable the OST and PSB functions. A combination of signals and the transfer of signals are present, and we ask the standard drafting team if the intent was to exclude all of the possible functionalities/associated signals capable from an OST and PSB. |
| <p><b>Response:</b> Thank you for your comment. The drafting team contends that OST and PSB functions within a substation are typically not a RAS. The drafting team contends that two or more exclusions taken together may or may not constitute a RAS. Individually, an exclusion is not a RAS; however, any of the exclusion(s) could be an integral part of a larger scheme that meets the RAS definition.</p> |           |   |
| SERC Protection and Controls Subcommittee   | Yes       |   |
| IRC Standards Review Committee  | Yes       | 1. Exclusion “m.” should be limited to SSR protection schemes that act solely at the same station. It should read: “Sub-synchronous resonance (SSR) protection schemes that directly detect and act solely at the same station depending on sub-synchronous quantities (e.g. currents or torsional oscillations).”  |

| Organization   | Yes or No | Question 4 Comment   |
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|  |           | <p>2. Another exclusion (“n.”) should be added to exclude schemes that are specifically designed to restore load (often called load throw-over schemes) so that they are not considered RAS. An example of this is a 115-kV line that has load tapped off the middle. After a fault on the line, switches automatically open up at the tapped station and each end of the 115 kV line tries to pick up the load. The unfaulted end of the line will restore the load, and the faulted end will trip out and remain open. However, we do not believe that schemes which are taking actions such as automatic network reconfiguration to reenergize equipment that was tripped as a result of fault clearing which is not restoring load should be excluded.</p> |
| <p><b>Response:</b> Thank you for your comment.</p> <p>1. Exclusion (m) is consistent with present industry practices and the drafting team declines to make the suggested change. The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.</p> <p>2. The drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) “Automatic Reclosing schemes;” however, system reconfiguration schemes that transfer the load to another source typically would be a RAS.</p> |           |  |
| Bonneville Power Administration  | Yes       |  |
| ACES Standards Collaborators   | Yes       | We agree that the exclusion list is very detailed and helpful.   |
| <p><b>Response:</b> Thank you for your comment.</p>  |           |  |
| CenterPoint Energy   | Yes       | <p>1. (a) CenterPoint Energy believes the use of the capitalized term “UVLS Programs” is appropriate based upon the currently posted definition of “UVLS Program” that is proposed in NERC Project 2008-02 Undervoltage Load Shedding PRC-010-1.</p>   |

| Organization | Yes or No | Question 4 Comment  |
|--------------|-----------|---|
|              |           | <p>2. (b) CenterPoint Energy suggests changing “Autoreclosing schemes” to “Automatic reclosing schemes” (item d) to be consistent with other NERC documents, such as, Reliability Standard PRC-005-3 Protection System and Automatic Reclosing Maintenance.</p> <p>3. (c) The extensive list of what is not a RAS appears to be well developed with thirteen schemes specifically identified. However, with the opening sentence currently stating “The following do not individually constitute a RAS”, it appears to be a finite list that would require a revision of the definition to include other possible control schemes. To not limit the list, CenterPoint Energy recommends the opening sentence be changed to “The following are examples of schemes that do not constitute a RAS”. (d) CenterPoint Energy is concerned that the use of the term “individually” in the opening sentence, which currently states “The following do not individually constitute a RAS”, reduces the clarity and specificity of the definition. Without clarity, this could result in inconsistent application across regions. As an example, if an entity has both a UVLS Program on their system and FACTS devices at a few locations, are these installations now considered to be collectively a RAS as opposed to individually? Under the existing NERC definition for SPS that states “An SPS does not include (a) underfrequency of Undervoltage load shedding”, there would not be any confusion that these installations are not RAS. Of the thirteen items on the exclusions list, there is only one example (item d for autoreclosing) in the project FAQ document that provides insight of the team’s intention with the use of “individually”. CenterPoint Energy suggests deleting the word “individually” by changing the opening sentence to “The following are examples of schemes that do not constitute a RAS”. Alternately, it may be possible to develop additional wording in the definition to codify the intent of the use of the term “individually”. In addition, CenterPoint Energy recommends that the project FAQ document include additional examples to help clarify the intent.</p> |

| Organization  | Yes or No | Question 4 Comment  |
|---|-----------|---|
|   |           | <p>4. As an alternative to the FAQ document, NERC could instead develop an Applications Guidelines document, with specific examples, for the definition of RAS.</p>   |
| <p><b>Response:</b> Thank you for your comment.</p> <ol style="list-style-type: none"> <li>The drafting team combined the posted exclusions (b) and (c) into a single exclusion (b) for this posting that reads: “Schemes for automatic under-frequency load shedding (UFLS) and automatic under-voltage load shedding (UVLS) comprised of only distributed relays.” The drafting team tailored this exclusion to match the language of the recently-approved “UVLS Program” definition.</li> <li>The drafting team agrees and made the suggested change.</li> <li>The drafting team disagrees and declined to make the suggested change. In the cited example, if the few FACTS devices and a UVLS program are controlled independently from each other, they would not be collectively regarded as a RAS.</li> <li>The FAQ will remain as part of the documentation associated with the development of the RAS definition.</li> </ol> |           |   |
| Pepco Holdings Inc  | Yes       |   |
| American Transmission Company, LLC  | Yes       |   |
| Xcel Energy   | Yes       | <p>We also feel that sudden pressure relays (SPRs) should also be explicitly stated in item "e".</p>  |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees that SPRs are a legitimate example but declines to make the addition because the list is not intended to be all-inclusive.</p>   |           |   |
| Idaho Power   | Yes       | <p>We would like to see Protection System operations and fault clearing included as an exception. We feel this will better separate RAS actions from Protection System operations, e.g. fault clearing or generator loss of field tripping.</p> |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees and added a new exclusion (a) which reads: Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements.</p>  |           |   |



| Organization  | Yes or No | Question 4 Comment  |
|---|-----------|---|
| Nebraska Public Power District  | Yes       |   |
| ITC   | Yes       |   |
| NV Energy   | Yes       |   |
| Ameren  | Yes       | Editorial: add semi-colon after each lettered item in the exclusion list. |
| <p><b>Response:</b> Thank you for your comment. The drafting team followed the NERC Style Guide and semi-colons are not required.</p> |           |   |
| PJM Interconnection   | Yes       |   |
| Independent Electricity System Operator   | Yes       |   |
| Oncor Electric Delivery LLC   | Yes       |   |

**5. Do you agree with the time frames in the proposed Implementation Plan associated with the proposed definition of RAS? Please provide specific comments in support of your position.**

**Summary Consideration:**

Approximately 75% of commenters agreed with the time frames in the proposed Implementation Plan associated with the definition of RAS. The commenters that replied “no” to the question had a variety of thoughts and alternative approaches but overall did not offer any compelling argument to change the stated time frames. The drafting team reiterated that the Implementation Plan provides thirty-six (36) months from the time the definition is approved by an applicable governmental authority. The time is noted in the twelve (12) months leading up to the Effective Date of the standard plus the twenty four (24) months noted following the Effective Date. This only applies to existing schemes that must transition to RAS due to the revised definition. Future RAS are not subject to this Implementation Plan. When the drafting team revises the RAS-related standards, those standards will include their own implementation periods.

| Organization   | Yes or No | Question 5 Comment   |
|--|-----------|--|
| Florida Municipal Power Agency   | No        | A thorough review of all the standards and their use of Protection Systems should be factored into the implementation plan.  |
| <p><b>Response:</b> Thank you for your comment. The drafting team agrees that a thorough review of all standards is prudent and asserts that the time period provided in the Implementation Plan is sufficient to evaluate existing compliance programs regarding the definition change.</p> |           |  |
| SPP Standards Review Group   | No        | <ol style="list-style-type: none"> <li>1) We suggest extending the time frame from twenty-four (24) months to thirty-six (36) months. There are many elements that have to be considered when establishing a new RAS. For example, identifying new facilities/equipment, budgeting, outage coordination and receiving necessary approvals will require large amounts of time.</li> <li>2) We would like to commend the SPS SDT on the quality of the documents in this posting. We did not find a single typo/grammatical error that are so typically present in these postings. Well done and thank you.</li> </ol> |
| <p><b>Response:</b> Thank you for your comment.</p>  |           |  |

| Organization  | Yes or No | Question 5 Comment  |
|---|-----------|---|
| <p>1. As a point of clarification, the Implementation Plan already provides thirty-six (36) months from the time the definition is approved by an applicable governmental authority. The time is noted in the twelve (12) months leading up to the Effective Date of the standard plus the twenty four (24) months noted following the Effective Date. This only applies to existing schemes that must transition to RAS due to the revised definition. When the drafting team revises the RAS-related standards, those standards will include their own implementation periods.</p> <p>2. Thank you for your compliment.</p> |           |   |
| Tacoma Public Utilities   | No        | <p>Tacoma Power supports FMPA’s comments concerning Question 5. Furthermore, in the FAQ document, on page 7 of 8, under “What are the Implementation Plan time frames,” in the second paragraph, it should be 24 calendar months (or longer if the drafting team extends the timefram) from the effective date (see page 6 of the Implementation Plan), not 24 calendar months beyond the date of approval by a governmental authority.</p>   |
| <p><b>Response:</b> Thank you for your comments. Please refer to our responses to FMPA above. The language in the FAQ document has been clarified.</p>  |           |   |
| CenterPoint Energy  | No        | <p>CenterPoint Energy recommends implementing the proposed definition of RAS and retirement of SPS as soon as practicable to incorporate the clarifications and help provide consistent application across all regions more quickly. Instead of 12 months, we suggest the definition become effective the first day of the first quarter after needed approvals. As this change would impact the proposed implementation plan time frame for newly-identified RAS resulting from the revised definition, we suggest changing the proposed twenty-four (24) months to thirty-six (36) months after the Effective Date of the definition.</p> |
| <p><b>Response:</b> Thank you for your comments. The drafting team does not see any benefit in making the definition effective immediately. Either way, entities will have at least thirty-six (36) months to identify RAS and become compliant with the existing RAS-related standards. This applies only to existing schemes that must transition to RAS due to the revised definition. Future RAS are not subject to this Implementation Plan. The new RAS-related standards will have separate effective dates and implementation plans of their own.</p>   |           |   |
| City of Vineland  | No        |   |

| Organization  | Yes or No | Question 5 Comment   |
|---|-----------|--|
| ISO New England   | No        | 24 months will be needed due to all the changes in documentation that will be required to address the revised definition.  |
| <p><b>Response:</b> Thank you for your comment. The revisions to the RAS definition should not require substantial changes for existing RAS-related documentation. For newly identified RAS, the time necessary for revisions is provided for in the Implementation Plan.</p> |           |  |
| Manitoba Hydro  | No        | The effective date for the revised Reliability Standards should be specific for each revised standard, and it should be specified in each revised standard.  |
| <p><b>Response:</b> Thank you for your comment. The drafting team revised the Effective Dates of each standard such that it is standard specific. The timing of the Effective Dates for the standards will coincide with the Effective Date of the RAS definition.</p>        |           |  |
| Nebraska Public Power District  | No        | <p>Also, see SPP group comments. The FAQ document states: “The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS related Reliability Standards. It appears the RAS classification types that are to be included in the RAS reliability standards will be a significant change that needs to be clarified before a full identification of RAS schemes and subsequent design requirements can be accurately completed if they are to be used. If other NERC standards must be updated or rewritten such as PRC or TPL standards in conjunction with this definition to clarify classification changes it is recommended the implementation plan specify that the proposed definition implementation not become effective until or following the most critically related RAS standards that would be updated in order to avoid confusion how the definition relates to existing or as yet un-revised standards. The FAQ document states “The Implementation Plan also provides owners of newly identified RAS twenty-four (24) calendar months beyond the date of approval by a governmental authority to be fully compliant with all standards applicable to the revised definition of Remedial Action Scheme. The drafting team contends that twenty-four (24) calendar months provides the RAS owner sufficient time to become compliant with the revised standards proposed in</p> |

| Organization  | Yes or No | Question 5 Comment   |
|---|-----------|--|
|   |           | <p>the implementation Plan. If it is possible the RAS definition may include new schemes or require complete redundancy modifications near large generating plants that have long outage schedules due to any classification changes it seems the 2 year implementation time frame could be too short. It seems a minimum of 4 to 6 years for an implementation time frame would be more logical for modification changes based on the possible classification types. This would reduce the risk of unplanned or additional generation outages in order to meet this standard.</p>   |
| <p><b>Response:</b> Thank you for your comments. The drafting team does not see any benefit in making the definition effective immediately. Either way, entities will have at least thirty-six (36) months to identify RAS and become compliant with the existing RAS-related standards. This applies only to existing schemes that must transition to RAS due to the revised definition. Future RAS are not subject to this Implementation Plan. The new RAS-related standards will have separate effective dates and implementation plans of their own.</p> |           |  |
| Ameren  | No        | <ol style="list-style-type: none"> <li>1. Direct substitution of RAS for SPS works in almost all cases, except for PRC-005-2, and - 3 section 4 Applicability 4.2.4 where it contradicts part of your proposed RAS definition “These schemes are not Protection Systems; however, they may share components with Protection Systems.” We request the drafting team reword PRC-005-2 and -3 section 4.2.4 by adding ‘Components’ and ‘part of’ to yield the following: “Protection System Components installed as part of a Remedial Action Scheme (RAS) for BES reliability.”</li> <li>2. We request the drafting team to drop the word ‘other’ that’s in front of ‘protection systems’ in PRC-012, PRC-013, PRC-014, PRC-015, and PRC-016 because it can be read to imply that a RAS is a protection system, which contradicts with part of your proposed RAS definition “These schemes are not Protection Systems; however, they may share components with Protection Systems.”</li> </ol> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. Please see the drafting team’s response to FMPA for Question 1.</li> </ol>   |           |  |

| Organization  | Yes or No | Question 5 Comment   |
|---|-----------|--|
| <p>2. The drafting team is currently developing only the RAS definition. The RAS-related standards development will begin in 2015 subsequent to the approval of the new definition. Any changes to other standards needed related to the new definition of RAS will occur at that time. The current standard changes proposed are only intended to accomplish the replacement of the term SPS with RAS.</p> |           |  |
| Austin Energy   | No        | A thorough review of all the standards and their use of Protection Systems should be factored into the implementation plan.  |
| <p>3. <b>Response:</b> Thank you for your comments. Please see the drafting team’s response to FMPA for Question 5.</p>   |           |  |
| Northeast Power Coordinating Council  | Yes       |  |
| MRO NERC Standards Review Forum   | Yes       |  |
| Dominion  | Yes       |  |
| FirstEnergy Corp.   | Yes       |  |
| Operational Compliance  | Yes       |  |
| Duke Energy   | Yes       |  |
| SERC Protection and Controls Subcommittee   | Yes       | The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers. |
| IRC Standards Review Committee  | Yes       |  |

| Organization  | Yes or No | Question 5 Comment   |
|---|-----------|--|
| Bonneville Power Administration   | Yes       |  |
| Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | Yes       |  |
| ACES Standards Collaborators  | Yes       | We agree with the time frame of 12 months after regulatory approval for the effective date of the standard. We also agree with the time frame for application of standards to newly identified RAS which is 24 months after the revised definition for newly identified RAS. |
| <b>Response:</b> Thank you for your comments and support.   |           |  |
| PacifiCorp  | Yes       |  |
| Orlando Utilities Commission  | Yes       |  |
| Central Lincoln   | Yes       |  |
| Wisconsin Electric Power Company  | Yes       |  |
| Pepco Holdings Inc  | Yes       |  |

| Organization   | Yes or No | Question 5 Comment   |
|--|-----------|--|
| Ingleside Cogeneration LP  | Yes       |  |
| American Transmission Company, LLC   | Yes       |  |
| Xcel Energy  | Yes       |  |
| MidAmerican Energy Company   | Yes       |  |
| Idaho Power  | Yes       | The initial 12 month period to identify new RAS appears to be adequate. However, the 24 month calendar should start once a new RAS is identified rather than the effective date of the definition. |
| <p><b>Response:</b> Thank you for your comment. The drafting team contends the thirty-six (36) months (at a minimum) that entities will have to identify RAS and become compliant with the existing RAS-related standards is sufficient.</p> |           |  |
| Exelon Companies   | Yes       |  |
| Omaha Public Power District  | Yes       |  |
| NV Energy  | Yes       |  |
| LCRA Transmission Services Corporation   | Yes       |  |
| Consumers Energy Company   | Yes       |  |
| PJM Interconnection  | Yes       |  |



| Organization  | Yes or No | Question 5 Comment  |
|---|-----------|---|
| Independent Electricity System Operator   | Yes       |   |
| Oncor Electric Delivery LLC   | Yes       | The RAP and SPS definition are already being used within ERCOT and apply to and are referenced in numerous guides, procedures and protocols. Many of ERCOTs RAP's are not automatic and are used frequently within the system to maintain reliability under various operating conditions. Updating SPS to the new term RAS through ERCOT's process of revising their documents will not only be a significant challenge but could also cause confusion with the RAP term. |
| <p><b>Response:</b> Thank you for your comments. The drafting team appreciates the fact that the selected term will cause some necessary documentation changes for many entities. The drafting team asserts that the use of the single term RAS will ensure consistency and avoid the confusion associated with the SPS term. The drafting team acknowledges that entities will need time to adapt to the RAS term.</p> |           |   |
| Tri-State Generation and Transmission Association, Inc.   | Yes       |   |
| Colorado Springs Utilities  |           | No Comments   |
| Tennessee Valley Authority  |           | Three years seems like a reasonable implementation period (a 1 year period for the definition to go into effect and a 2 year period for any existing scheme pulled into the definition to be brought into compliance). However, with 38 additional standards to be revised, this could entail more work than anticipated to ensure full compliance with each one under the new definition.  |
| <p><b>Response:</b> Thank you for your comments. The drafting team appreciates the fact that the selected term will cause some necessary documentation changes for many entities. The drafting team asserts that the use of the single term RAS will benefit the industry. The revised Reliability Standards will reflect the use of the single term RAS.</p>   |           |   |

**END OF REPORT**

## Proposed Definition of “Remedial Action Scheme”

### *Remedial Action Scheme (RAS)*

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic Reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Existing Definitions – Glossary of Terms Used in NERC Reliability Standards

### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

### *Remedial Action Scheme*

See “Special Protection System”

## Proposed Definition of “Remedial Action Scheme”

### *Remedial Action Scheme (RAS)*

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, ~~curtailing adjusting~~ or tripping generation ~~or other sources,~~ ~~curtailing or (MW and Mvar),~~ tripping load, or reconfiguring a System(s). RAS accomplish ~~one or more of the following~~ objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable System BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading; or
- ~~Address other Bulk Electric System (BES) reliability concerns.~~

~~These schemes are not Protection Systems; however, they may share components with Protection Systems extreme events.~~

The following do not individually constitute a RAS:

- ~~a.~~ Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- ~~b.~~ Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- ~~a-c.~~ Out-of-step tripping and power swing blocking
- ~~a.~~ Automatic ~~underfrequency load shedding (UFLS) programs~~
- ~~b.~~ ~~Undervoltage Load Shedding Programs (UVLS Programs)~~
- ~~b-d.~~ Autoreclosing/Reclosing schemes
- ~~e-e.~~ Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high voltage overvoltage, or overload to protect the Element against damage by removing it from service
- ~~d-f.~~ Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers, ~~or generation excitation,~~; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

- ~~e.g.~~ FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- ~~f.h.~~ Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- ~~g.i.~~ Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- ~~h.j.~~ Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- ~~i.k.~~ Automatic sequences that proceed when manually initiated solely by ~~an operator~~ a System Operator
- ~~j.l.~~ Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- ~~k.m.~~ \_\_\_\_\_ Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## **Existing ~~NERC Definitions~~ – Glossary of Terms ~~Definitions~~ Used in NERC Reliability Standards**

### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

### *Remedial Action Scheme*

See “Special Protection System”

# Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## Project 2010-05.2 – Special Protection Systems

### Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. This “broadness,” however, necessitates an exclusion list because without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT is coordinating the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT is introducing a new NERC Glossary term, UVLS Program, to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: “An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.”

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agrees with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to

centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

**Requested Approvals**

Definition of “**Remedial Action Scheme**” and the standards listed below

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of “Remedial Action Scheme” becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

The standard numbers below currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

- |                   |                |                |
|-------------------|----------------|----------------|
| CIP-002-3(X)      | PRC-005-2(X)   | PRC-023-2(X)   |
| CIP-002-3b(X)     | PRC-005-3(X)   | PRC-023-3(X)   |
| EOP-004-2(X)      | PRC-006-1(X)   | PRC-024-1(X)   |
| FAC-010-2.1(X)    | PRC-012-0(X)   | PRC-025-1(X)   |
| FAC-011-2(X)      | PRC-013-0(X)   | TOP-005-2a(X)  |
| IRO-005-3.1a(X)   | PRC-014-0(X)   | TPL-001-0.1(X) |
| MOD-029-1a(X)     | PRC-015-0(X)   | TPL-002-0b(X)  |
| MOD-030-2(X)      | PRC-016-0.1(X) | TPL-003-0b(X)  |
| NUC-001-2.1(X)    | PRC-017-0(X)   | TPL-004-0a(X)  |
| PRC-001-1.1(X)    | PRC-020-1(X)   |                |
| PRC-004-WECC-1(X) | PRC-021-1(X)   |                |

**Requested Retirements**

- |              |                |             |
|--------------|----------------|-------------|
| CIP-002-3    | PRC-004-WECC-1 | PRC-020-1   |
| CIP-002-3b   | PRC-005-2      | PRC-021-1   |
| EOP-004-2    | PRC-005-3      | PRC-023-2   |
| FAC-010-2.1  | PRC-006-1      | PRC-023-3   |
| FAC-011-2    | PRC-012-0      | PRC-024-1   |
| IRO-005-3.1a | PRC-013-0      | PRC-025-1   |
| MOD-029-1a   | PRC-014-0      | TOP-005-2a  |
| MOD-030-02   | PRC-015-0      | TPL-001-0.1 |
| NUC-001-2.1  | PRC-016-0.1    | TPL-002-0b  |
| PRC-001-1.1  | PRC-017-0      | TPL-003-0b  |



TPL-004-0a

### General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly identified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(X) and PRC-005-3(X). These implementation plans are incorporated here by reference.

### Prerequisite Approvals

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding  
Definition of “Undervoltage Load Shedding Program (UVLS Program)” in Project 2008-02 Undervoltage Load Shedding

### Revisions to the NERC Glossary of Terms

The drafting team proposes the following revised definition:

#### Remedial Action Scheme (RAS)

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic Reclosing schemes

- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

### **Conforming Changes to Other Standards**

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

### **Effective Date for Revised Reliability Standards and Definition**

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

PRC-024-1(X) shall become effective on the later of the Effective Date of PRC-024-1 or the first day of the first calendar quarter that is twelve (12) months after the date the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, PRC-024-1(X) shall become effective on the later of the Effective Date of PRC-024-1 or on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### **Implementation Plan for Newly Identified Remedial Action Schemes (RAS)**

Entities with newly identified “Remedial Action Scheme” (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

### **Retirement of Existing Standards and Definitions**

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of “Remedial Action Scheme” shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of “Remedial Action Scheme”.

# Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## Project 2010-05.2 – Special Protection Systems

### Background

The existing [NERC Glossary of Terms Used in NERC Reliability Standards](#) definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS ~~or~~ /RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS ~~or~~ /RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. This “broadness,” however, necessitates an exclusion list because without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT is coordinating the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT is introducing a new NERC Glossary term, UVLS Program, to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: “An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.”

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agrees with this assessment and revised the definition of RAS to clarify that it is [exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is](#) inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to

centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

**Requested Approvals**

Definition of “**Remedial Action Scheme**” and the standards listed below

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of “Remedial Action Scheme” becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

The standard numbers below currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to BOT adoption.

|                           |                         |                         |
|---------------------------|-------------------------|-------------------------|
| CIP-002-3(X)              | IRO-005-3.1a(X)         | PRC-017-0(X)            |
| CIP-002-3b(X)             | <del>IRO-014-1(X)</del> | PRC-020-1(X)            |
| <del>CIP-002-5.1(X)</del> | MOD-029-1a(X)           | PRC-021-1(X)            |
| <del>CIP-003-5(X)</del>   | MOD-030-2(X)            | PRC-023-2(X)            |
| <del>CIP-004-5.1(X)</del> | NUC-001-2.1(X)          | PRC-023-3(X)            |
| <del>CIP-005-5(X)</del>   | PRC-001-1.1(X)          | PRC-024-1(X)            |
| <del>CIP-006-5(X)</del>   | PRC-004-WECC-1(X)       | PRC-025-1(X)            |
| <del>CIP-007-5(X)</del>   | PRC-005-2(X)            | TOP-005-2a(X)           |
| <del>CIP-008-5(X)</del>   | PRC-005-3(X)            | TPL-001-0.1(X)          |
| <del>CIP-009-5(X)</del>   | PRC-006-1(X)            | <del>TPL-001-4(X)</del> |
| <del>CIP-010-1(X)</del>   | PRC-012-0(X)            | TPL-002-0b(X)           |
| <del>CIP-011-1(X)</del>   | PRC-013-0(X)            | TPL-003-0b(X)           |
| EOP-004-2(X)              | PRC-014-0(X)            | TPL-004-0a(X)           |
| FAC-010-2.1(X)            | PRC-015-0(X)            |                         |
| FAC-011-2(X)              | PRC-016-0.1(X)          |                         |

**Requested Retirements**

Definition of “~~Special Protection System~~” and the standards listed below

|                        |                        |                      |
|------------------------|------------------------|----------------------|
| CIP-002-3              | <del>CIP-003-5</del>   | <del>CIP-006-5</del> |
| CIP-002-3b             | <del>CIP-004-5.1</del> | <del>CIP-007-5</del> |
| <del>CIP-002-5.1</del> | <del>CIP-005-5</del>   | <del>CIP-008-5</del> |

|                      |                |                      |
|----------------------|----------------|----------------------|
| <del>CIP-009-5</del> | PRC-004-WECC-1 | PRC-023-2            |
| <del>CIP-010-1</del> | PRC-005-2      | PRC-023-3            |
| <del>CIP-011-1</del> | PRC-005-3      | PRC-024-1            |
| EOP-004-2            | PRC-006-1      | PRC-025-1            |
| FAC-010-2.1          | PRC-012-0      | TOP-005-2a           |
| FAC-011-2            | PRC-013-0      | TPL-001-0.1          |
| IRO-005-3.1a         | PRC-014-0      | <del>TPL-001-4</del> |
| <del>IRO-014-1</del> | PRC-015-0      | TPL-002-0b           |
| MOD-029-1a           | PRC-016-0.1    | TPL-003-0b           |
| MOD-030-02           | PRC-017-0      | TPL-004-0a           |
| NUC-001-2.1          | PRC-020-1      |                      |
| PRC-001-1.1          | PRC-021-1      |                      |

**General Considerations**

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly-identified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(X) and PRC-005-3(X). These implementation plans are incorporated here by reference.

**Prerequisite Approvals**

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding  
 Definition of “Undervoltage Load Shedding Program (UVLS Program)” in Project 2008-02 Undervoltage Load Shedding

**Revisions to the NERC Glossary of Terms**

The drafting team proposes the following revised definition:

**Remedial Action Scheme (RAS)**

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, ~~curtailing adjusting~~ or tripping generation ~~or other sources,~~ ~~curtailing or (MW and Mvar),~~ tripping load, or reconfiguring a System(s). RAS accomplish ~~one or more of the following~~ objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable ~~System~~BES voltages;

- Maintain acceptable BES power flows;
- Limit the impact of Cascading; or extreme events.
- ~~Address other Bulk Electric System (BES) reliability concerns.~~

~~These schemes are not Protection Systems; however, they may share components with Protection Systems.~~

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- ~~a-c.~~ Out-of-step tripping and power swing blocking
- ~~a.~~ Automatic underfrequency load shedding (UFLS) programs
- ~~b.~~ Undervoltage Load Shedding Programs (UVLS Programs)
- ~~b-d.~~ Autoreclosing/Reclosing schemes
- ~~e-e.~~ Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, high-voltage overvoltage, or overload to protect the Element against damage by removing it from service
- ~~d-f.~~ Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers, ~~or generation excitation;~~ and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- ~~e-g.~~ FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- ~~f-h.~~ Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- ~~g-i.~~ Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- ~~h-j.~~ Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- ~~i-k.~~ Automatic sequences that proceed when manually initiated solely by ~~an operator~~ System Operator
- ~~j-l.~~ Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

- ~~k.m.~~ Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

### Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

### Effective Date for Revised Reliability Standards and Definition

~~The~~ Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

PRC-024-1(X) shall become effective on the later of the Effective Date of PRC-024-1 or the first day of the first calendar quarter that is twelve (12) months after the date the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, PRC-024-1(X) shall become effective on the later of the Effective Date of PRC-024-1 or on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### Implementation Plan for Newly- Identified Remedial Action Schemes (RAS)

Entities with newly-identified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable ~~to the revised definition of "Remedial Action Scheme" RAS~~ twenty-four (24) months from the Effective Date of the revised definition of "Remedial Action Scheme." RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

### Retirement of Existing Standards and Definitions

The requested Reliability Standards for retirement, ~~the current definition of "Special Protection System," and the~~ shall be retired at midnight of the day immediately prior to the Effective Date of its successor



standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of “Remedial Action Scheme” shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of “Remedial Action Scheme”. ~~in the particular jurisdiction in which the revised definition is becoming effective.~~

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(X)
3. **Purpose:** NERC Standards CIP-002-3(X) through CIP-009-3(X) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on

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

**B. Requirements**

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
  - R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
  - R1.2.** The risk-based assessment shall consider the following assets:
    - R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
    - R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
    - R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
    - R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
    - R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
    - R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
    - R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
  - R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
  - R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
  - R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical

Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

- 1.5.1** None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2       |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3       |                   | Updated version number from -2 to -3  |  |
| 3       | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
| 3(X)    | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard CIP-002-3(X) — Cyber Security — Critical Cyber Asset Identification

### A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(X)
3. **Purpose:** NERC Standards CIP-002-3(X) through CIP-009-3(X) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

#### 4. Applicability:

4.1. Within the text of Standard CIP-002-3(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on

**Deleted:** The first day of the third calendar quarter after applicable regulatory approvals<sup>¶</sup>  
<#>have been received (or the Reliability Standard otherwise becomes effective the first day of the<sup>¶</sup>  
<#>third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is<sup>¶</sup> not required)

**Deleted: Approved by Board of Trustees: December 16, 2009**

## Standard CIP-002-3(X) — Cyber Security — Critical Cyber Asset Identification

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

### B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical

Deleted: Special Protection Systems

Deleted: Approved by Board of Trustees: December 16, 2009

## Standard CIP-002-3(X) — Cyber Security — Critical Cyber Asset Identification

Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

### C. Measures

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

##### 1.3. Compliance Monitoring and Enforcement Processes

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

##### 1.4. Data Retention

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

##### 1.5. Additional Compliance Information

- 1.5.1** None.

Deleted: Approved by Board of Trustees: December 16, 2009



**Standard CIP-002-3(X) — Cyber Security — Critical Cyber Asset Identification**

**2. Violation Severity Levels (To be developed later.)**

**E. Regional Variances**

None identified.

**Version History**

| Version     | Date              | Action  | Change Tracking   |
|-------------|-------------------|---|---|
| 1           | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata  |
| 2           |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3           |                   | Updated version number from -2 to -3  |   |
| 3           | December 16, 2009 | Approved by the NERC Board of Trustees  | Update  |
| <u>3(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Deleted: Approved by Board of Trustees: December 16, 2009

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3b(X)
3. **Purpose:** NERC Standards CIP-002-3b(X) through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3b(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3b(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3b(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval

by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## **B. Requirements**

- R1. Critical Asset Identification Method** — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
  - R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
  - R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
  - R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
  - R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
  - R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
  - R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2. Critical Asset Identification** — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3. Critical Cyber Asset Identification** — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3b(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

**1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3b(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

**1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

**1.5.1** None.

2. Violation Severity Levels

| Requirement | VRF    | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-------------|--------|-----------|---|---|--|
| R1.         | MEDIUM | N/A       | N/A   | N/A   | The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.                 |
| R1.1.       | LOWER  | N/A       | The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures. | The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria. | The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria. |
| R1.2.       | MEDIUM | N/A       | N/A   | N/A   | The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.                             |
| R1.2.1.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.2.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.3.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.4.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.5.     | LOWER  | N/A       | N/A   | N/A   | N/A  |

Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification

| Requirement | VRF   | Lower VSL | Moderate VSL  | High VSL   | Severe VSL   |
|-------------|-------|-----------|---|--|--|
| R1.2.6.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R1.2.7.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R2.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.  | The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.   |
| R3.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required. | The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null. |
| R3.1.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.2.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.3.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R4.         | LOWER | N/A       | The Responsible Entity does not have a signed and dated | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual   | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of   |

**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

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| Requirement | VRF | Lower VSL | Moderate VSL   | High VSL   | Severe VSL  |
|-------------|-----|-----------|--|--|---|
|             |     |           | record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets <b>or</b> the list of Critical Cyber Assets (even if such lists are null.) | approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.) | 1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.) |



**E. Regional Variances**

None identified.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2       |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3       |                   | Updated version number from -2 to -3  |  |
| 3       | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
| 3a      | May 9, 2012       | Interpretation of R3 for Duke Energy adopted by the NERC Board of Trustees  |  |
| 3b      | February 7, 2013  | Interpretation of R1.2.5 for OGE adopted by the NERC Board of Trustees  |  |
| 3b      | March 21, 2013    | FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)  |  |
| 3b(X)   | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Appendix 1

**Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation**

Date submitted: 2/24/11

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

**Requirement Number and Text of Requirement**

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

**Identify specifically what requirement needs clarification (as submitted):**

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

### **Question Summary**

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

### **Response**

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

## Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification

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### A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3b(X)
3. **Purpose:** NERC Standards CIP-002-3b(X) through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3b(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

#### 4. **Applicability:**

4.1. Within the text of Standard CIP-002-3b(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3b(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval

## Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification

by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3b(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

**Deleted:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

**Deleted:** Special Protection System

- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

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**1.4. Data Retention**

**1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3b(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

**1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

**1.5.1** None.

2. Violation Severity Levels

| Requirement | VRF    | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-------------|--------|-----------|---|---|--|
| R1.         | MEDIUM | N/A       | N/A   | N/A   | The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.                 |
| R1.1.       | LOWER  | N/A       | The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures. | The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria. | The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria. |
| R1.2.       | MEDIUM | N/A       | N/A   | N/A   | The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.                             |
| R1.2.1.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.2.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.3.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.4.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.5.     | LOWER  | N/A       | N/A   | N/A   | N/A  |



**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

| Requirement | VRF   | Lower VSL | Moderate VSL  | High VSL   | Severe VSL   |
|-------------|-------|-----------|---|--|--|
| R1.2.6.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R1.2.7.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R2.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.  | The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.   |
| R3.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required. | The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null. |
| R3.1.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.2.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.3.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R4.         | LOWER | N/A       | The Responsible Entity does not have a signed and dated | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual   | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of   |

**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

| Requirement | VRF | Lower VSL | Moderate VSL   | High VSL   | Severe VSL  |
|-------------|-----|-----------|--|--|---|
|             |     |           | record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets <b>or</b> the list of Critical Cyber Assets (even if such lists are null.) | approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.) | 1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.) |

**E. Regional Variances**

None identified.

**Version History**

| Version          | Date              | Action  | Change Tracking   |
|------------------|-------------------|---|---|
| 1                | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata  |
| 2                |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |   |
| 3                |                   | Updated version number from -2 to -3  |   |
| 3                | December 16, 2009 | Approved by the NERC Board of Trustees  | Update  |
| 3a               | May 9, 2012       | Interpretation of R3 for Duke Energy adopted by the NERC Board of Trustees  |   |
| 3b               | February 7, 2013  | Interpretation of R1.2.5 for OGE adopted by the NERC Board of Trustees  |   |
| 3b               | March 21, 2013    | FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)  |   |
| <del>3b(X)</del> | <del>TBD</del>    | <del>Adopted by the NERC Board of Trustees</del>  | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |

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Appendix 1

| Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation   |  |
|--|--|
| Date submitted: 2/24/11  |  |
| The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.   |  |
| Requirement Number and Text of Requirement   |  |
| R1.Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.<br><br>R1.2. The risk-based assessment shall consider the following assets:<br><br>R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.   |  |
| Identify specifically what requirement needs clarification (as submitted):   |  |
| Requirement Number and Text of Requirement:<br>CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.<br><br>Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.<br><br>The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.<br><br>OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding |  |

**Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification**

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

**Question Summary**

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

**Response**

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

### A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2(X)
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider
5. **Effective Dates:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

  1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
  2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
  3. Specific references to the DOE form need to be eliminated.
  4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2(X) Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
  
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2(X) Attachment 1 and in accordance with the entity responsible for reporting.
  
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
  
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2(X) Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

## **C. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1 Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### **1.2 Evidence Retention**

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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



**1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br><br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |

| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)

**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |

**EOP-004-2(X) — Event Reporting**

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq$ 100 MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq$ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm$ 10% of nominal voltage sustained for $\geq$ 15 continuous minutes.   |

**EOP-004-2(X) — Event Reporting**

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |

**EOP-004-2(X) — Event Reporting**

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| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |



EOP-004 - Attachment 2: Event Reporting Form

| <b>EOP-004 Attachment 2: Event Reporting Form</b>   |  |
|---|--|
| <p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a> , Facsimile 404-446-9770 or voice: 404-446-9780.</p> |  |
| Task  | Comments   |
| 1.  | <p>Entity filing the report include:<br/>                     Company name:<br/>                     Name of contact person:<br/>                     Email address of contact person:<br/>                     Telephone Number:<br/>                     Submitted by (name):</p>  |
| 2.  | <p>Date and Time of recognized event.<br/>                     Date: (mm/dd/yyyy)<br/>                     Time: (hh:mm)<br/>                     Time/Zone:</p>   |
| 3.  | <p>Did the event originate in your system?      Yes <input type="checkbox"/>    No <input type="checkbox"/>    Unknown <input type="checkbox"/></p>  |
| 4.  | <p style="text-align: center;"><b>Event Identification and Description:</b></p> <p>(Check applicable box)</p> <p><input type="checkbox"/> Damage or destruction of a Facility</p> <p><input type="checkbox"/> Physical Threat to a Facility</p> <p><input type="checkbox"/> Physical Threat to a control center</p> <p><input type="checkbox"/> BES Emergency:</p> <p style="padding-left: 20px;"><input type="checkbox"/> public appeal for load reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> system-wide voltage reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> manual firm load shedding</p> <p style="padding-left: 20px;"><input type="checkbox"/> automatic firm load shedding</p> <p><input type="checkbox"/> Voltage deviation on a Facility</p> <p><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)</p> <p><input type="checkbox"/> Loss of firm load</p> <p><input type="checkbox"/> System separation</p> <p><input type="checkbox"/> Generation loss</p> <p><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)</p> <p><input type="checkbox"/> Transmission loss</p> <p><input type="checkbox"/> unplanned control center evacuation</p> <p><input type="checkbox"/> Complete loss of voice communication capability</p> <p><input type="checkbox"/> Complete loss of monitoring capability</p> <p style="text-align: right;">Written description (optional):</p> |

## Guideline and Technical Basis

### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather than submitting three reports as each individual registered entity.

### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

## **EOP-004-2(X) — Event Reporting**

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reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### **Data Gathering**

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2(X) specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2(X) may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### **Law Enforcement Reporting**

The reliability objective of EOP-004-2(X) is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### **Stakeholders in the Reporting Process**

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

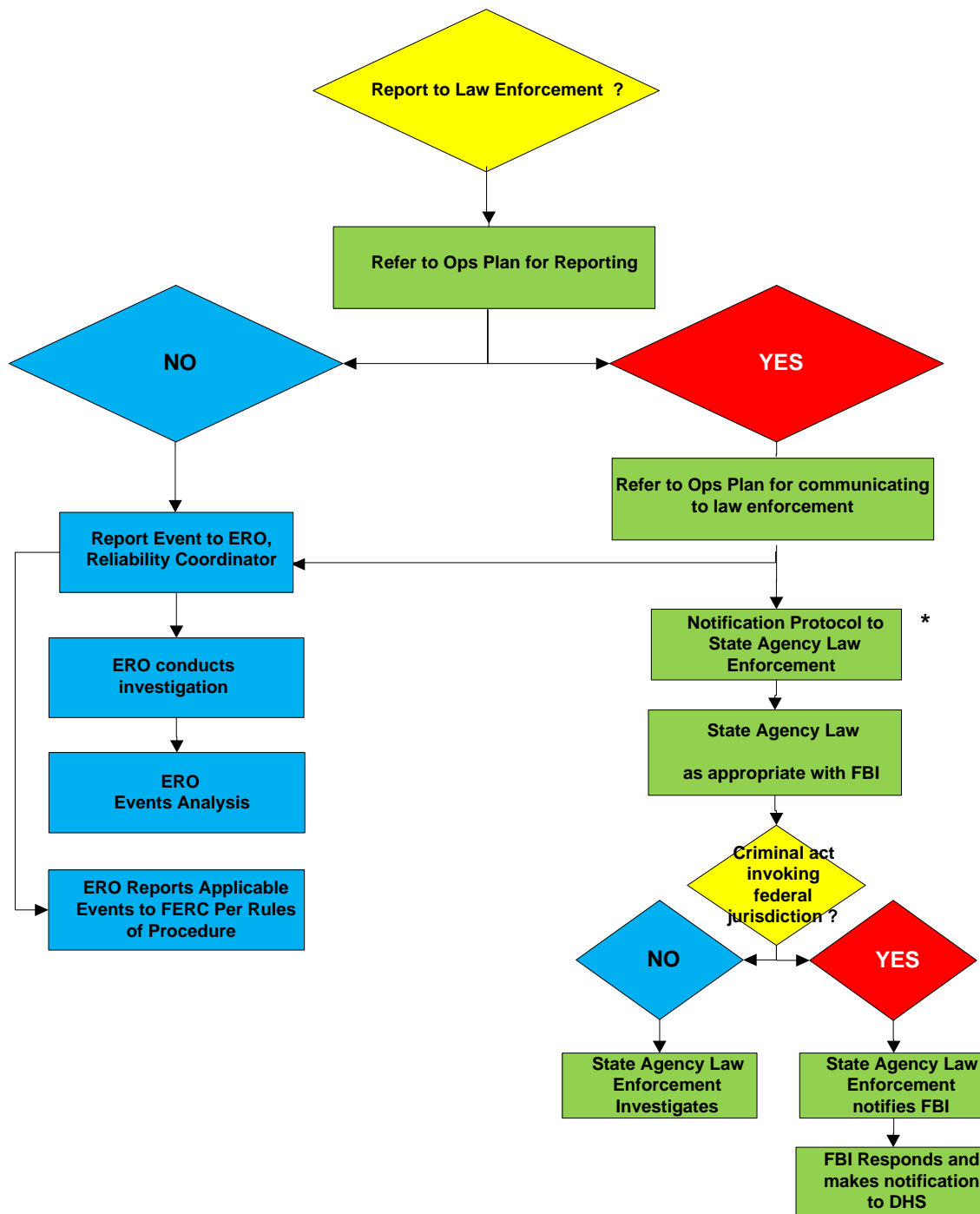
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

### Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

#### Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

#### Summary of Concepts and Assumptions:

##### *The Standard:*

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

##### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### **Discussion of Event Reporting**

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### ***What about sabotage?***

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.



### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2(X) Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

## Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 2       |                  | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)  |
| 2       | November 7, 2012 | Adopted by the NERC Board of Trustees  |  |
| 2       | June 20, 2013    | FERC approved  |  |
| 2(X)    | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## EOP-004-2(X) — Event Reporting

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### A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2(X)
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider
5. **Effective Dates:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

  1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
  2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
  3. Specific references to the DOE form need to be eliminated.
  4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

**Deleted:** The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.¶

## EOP-004-2(X) — Event Reporting

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The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2(X) Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2(X) Attachment 1 and in accordance with the entity responsible for reporting.
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2(X) Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

## EOP-004-2(X) — Event Reporting

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end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium]*  
*[Time Horizon: Operations Planning]*
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

### C. Compliance

#### 1. Compliance Monitoring Process

##### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

##### 1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

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**1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |



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| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)

**EOP-004-2(X) — Event Reporting**

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**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

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**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |

**EOP-004-2(X) — Event Reporting**

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq$ 100 MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq$ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm$ 10% of nominal voltage sustained for $\geq$ 15 continuous minutes.   |

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EOP-004-2(X) — Event Reporting

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |

**EOP-004-2(X) — Event Reporting**

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| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |

EOP-004 - Attachment 2: Event Reporting Form

| EOP-004 Attachment 2: Event Reporting Form  |   |   |                                 |
|---|---|---|---------------------------------|
| <p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a>, Facsimile 404-446-9770 or voice: 404-446-9780.</p>  |   |   |                                 |
| Task  | Comments  |   |                                 |
| 1.  | Entity filing the report include:<br>Company name:<br>Name of contact person:<br>Email address of contact person:<br>Telephone Number:<br>Submitted by (name):  |   |                                 |
| 2.  | Date and Time of recognized event.<br>Date: (mm/dd/yyyy)<br>Time: (hh:mm)<br>Time/Zone:   |   |                                 |
| 3.  | Did the event originate in your system?    Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/>  |   |                                 |
| 4.  | <p style="text-align: center;"><b>Event Identification and Description:</b></p> <table border="0" style="width: 100%;"> <tr> <td style="width: 40%; vertical-align: top;">                             (Check applicable box)<br/> <input type="checkbox"/> Damage or destruction of a Facility<br/> <input type="checkbox"/> Physical Threat to a Facility<br/> <input type="checkbox"/> Physical Threat to a control center<br/> <input type="checkbox"/> BES Emergency:<br/>                                 <input type="checkbox"/> public appeal for load reduction<br/>                                 <input type="checkbox"/> system-wide voltage reduction<br/>                                 <input type="checkbox"/> manual firm load shedding<br/>                                 <input type="checkbox"/> automatic firm load shedding<br/> <input type="checkbox"/> Voltage deviation on a Facility<br/> <input type="checkbox"/> IROL Violation (all Interconnections) or<br/>                                 SOL Violation for Major WECC Transfer<br/>                                 Paths (WECC only)<br/> <input type="checkbox"/> Loss of firm load<br/> <input type="checkbox"/> System separation<br/> <input type="checkbox"/> Generation loss<br/> <input type="checkbox"/> Complete loss of off-site power to a<br/>                                 nuclear generating plant (grid supply)<br/> <input type="checkbox"/> Transmission loss<br/> <input type="checkbox"/> unplanned control center evacuation<br/> <input type="checkbox"/> Complete loss of voice communication<br/>                                 capability<br/> <input type="checkbox"/> Complete loss of monitoring capability                         </td> <td style="width: 60%; vertical-align: top;">                             Written description (optional):                         </td> </tr> </table> | (Check applicable box)<br><input type="checkbox"/> Damage or destruction of a Facility<br><input type="checkbox"/> Physical Threat to a Facility<br><input type="checkbox"/> Physical Threat to a control center<br><input type="checkbox"/> BES Emergency:<br><input type="checkbox"/> public appeal for load reduction<br><input type="checkbox"/> system-wide voltage reduction<br><input type="checkbox"/> manual firm load shedding<br><input type="checkbox"/> automatic firm load shedding<br><input type="checkbox"/> Voltage deviation on a Facility<br><input type="checkbox"/> IROL Violation (all Interconnections) or<br>SOL Violation for Major WECC Transfer<br>Paths (WECC only)<br><input type="checkbox"/> Loss of firm load<br><input type="checkbox"/> System separation<br><input type="checkbox"/> Generation loss<br><input type="checkbox"/> Complete loss of off-site power to a<br>nuclear generating plant (grid supply)<br><input type="checkbox"/> Transmission loss<br><input type="checkbox"/> unplanned control center evacuation<br><input type="checkbox"/> Complete loss of voice communication<br>capability<br><input type="checkbox"/> Complete loss of monitoring capability | Written description (optional): |
| (Check applicable box)<br><input type="checkbox"/> Damage or destruction of a Facility<br><input type="checkbox"/> Physical Threat to a Facility<br><input type="checkbox"/> Physical Threat to a control center<br><input type="checkbox"/> BES Emergency:<br><input type="checkbox"/> public appeal for load reduction<br><input type="checkbox"/> system-wide voltage reduction<br><input type="checkbox"/> manual firm load shedding<br><input type="checkbox"/> automatic firm load shedding<br><input type="checkbox"/> Voltage deviation on a Facility<br><input type="checkbox"/> IROL Violation (all Interconnections) or<br>SOL Violation for Major WECC Transfer<br>Paths (WECC only)<br><input type="checkbox"/> Loss of firm load<br><input type="checkbox"/> System separation<br><input type="checkbox"/> Generation loss<br><input type="checkbox"/> Complete loss of off-site power to a<br>nuclear generating plant (grid supply)<br><input type="checkbox"/> Transmission loss<br><input type="checkbox"/> unplanned control center evacuation<br><input type="checkbox"/> Complete loss of voice communication<br>capability<br><input type="checkbox"/> Complete loss of monitoring capability | Written description (optional):   |   |                                 |

## Guideline and Technical Basis

### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to



## **EOP-004-2(X) — Event Reporting**

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reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### **Data Gathering**

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2(X) specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2(X) may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### **Law Enforcement Reporting**

The reliability objective of EOP-004-2(X) is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### **Stakeholders in the Reporting Process**

- Industry

## EOP-004-2(X) — Event Reporting

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- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

## **EOP-004-2(X) — Event Reporting**

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coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

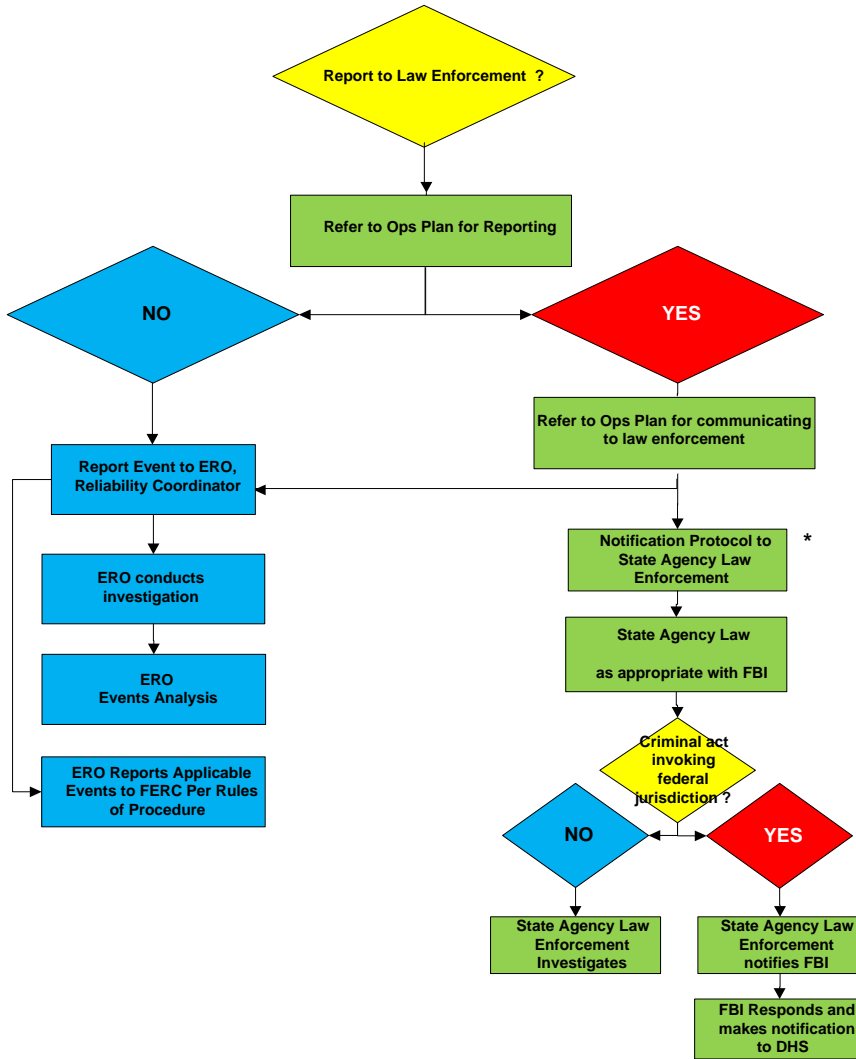
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

## Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

### Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

### Summary of Concepts and Assumptions:

#### *The Standard:*

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

#### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

## EOP-004-2(X) — Event Reporting

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3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### Discussion of Event Reporting

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### What about sabotage?

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *" . . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

## EOP-004-2(X) — Event Reporting

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### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

#### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

## EOP-004-2(X) — Event Reporting

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how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2(X) Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.



## EOP-004-2(X) — Event Reporting

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### Version History

| Version     | Date             | Action   | Change Tracking   |
|-------------|------------------|--|---|
| 2           |                  | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)   |
| 2           | November 7, 2012 | Adopted by the NERC Board of Trustees  |   |
| 2           | June 20, 2013    | FERC approved  |   |
| <u>2(X)</u> | <u>TBD</u>       | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

**A. Introduction**

- 1. Title:** System Operating Limits Methodology for the Planning Horizon
- 2. Number:** FAC-010-2.1(X)
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
  - 4.1. Planning Authority**
- 5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1.** The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1.** Be applicable for developing SOLs used in the planning horizon.
  - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
  - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1.** In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2.** Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1.** Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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- R2.3.** Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
  - R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
  - R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
- R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
  - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
  - R3.2.** Selection of applicable Contingencies.
  - R3.3.** Level of detail of system models used to determine SOLs.
  - R3.4.** Allowed uses of Remedial Action Schemes.
  - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
  - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
  - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
  - R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### C. Measures

- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

##### 1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

##### 1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

###### 1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

###### 1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

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- 1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
- 2. **Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
  - 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology. **(Retirement approved by FERC effective January 21, 2014.)**
  - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
  - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
  - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6  |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |

**Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon**

| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |



## **E. Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

- 1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
- 1.3.1** Cascading does not occur.
- 1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

### Version History

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |

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|--------|-------------------|--|--|
| 2.1    | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |  |
| 2.1    | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.  |  |
| 2.1(X) | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

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### A. Introduction

1. **Title:** System Operating Limits Methodology for the Planning Horizon
2. **Number:** FAC-010-2.1(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Planning Authority
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: April 19, 2010

### B. Requirements

- R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the planning horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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- R2.3.** Starting with all Facilities in service, the system’s response to a single Contingency, may include any of the following:
  - R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
  - R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
- R2.6.** In determining the system’s response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
  - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
  - R3.2.** Selection of applicable Contingencies.
  - R3.3.** Level of detail of system models used to determine SOLs.
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- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
  - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority Area.
  - R4.3.** Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient

Deleted: Special Protection Systems or

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within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### C. Measures

- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

##### 1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

##### 1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

###### 1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)

###### 1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

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- 1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
- 2. **Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
  - 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)
  - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
  - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
  - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

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**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |



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| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |

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| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

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**E. Regional Differences**

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a [Remedial Action Scheme](#) to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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**1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

**1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

**1.3.1** Cascading does not occur.

**1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |

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|---------------|-------------------|--|---|
| 2.1           | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |   |
| 2.1           | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.  |   |
| <u>2.1(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-2(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the operations horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
- R2.3.** In determining the system's response to a single Contingency, the following shall be acceptable:
  - R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
  - R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
  - R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
  - R3.2.** Selection of applicable Contingencies
  - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
    - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
  - R3.4.** Level of detail of system models used to determine SOLs.
  - R3.5.** Allowed uses of Remedial Action Schemes.
  - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
  - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
  - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.
  - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.

- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### **C. Measures**

- M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

##### **1.3. Data Retention**

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

##### **1.4. Additional Compliance Information**



The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

**1.4.1** SOL Methodology.

**1.4.2** Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)

**1.4.3** Superseded portions of its SOL Methodology that had been made within the past 12 months.

**1.4.4** Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

**2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**

**2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

**2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

**2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology  
(Retirement approved by FERC effective January 21, 2014.)

**2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

**2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:

**2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

**2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

**2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

**2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |

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| Requirement   | Lower   | Moderate  | High  | Severe   |
|---|---|---|---|--|
|   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>   |
| <p>R5<br/>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

## **Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | November 1, 2006  | Adopted by Board of Trustees  | New  |
| 2       |                   | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised  |
| 2       | June 24, 2008     | Adopted by Board of Trustees: FERC Order 705  | Revised  |
| 2       | January 22, 2010  | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update   |
| 2       | February 7, 2013  | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |  |
| 2       | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |  |
| 2       | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.   |  |
| 2(X)    | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard FAC-011-2(X) — System Operating Limits Methodology for the Operations Horizon

### A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-2(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: April 29, 2009

### B. Requirements

- R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the operations horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.



**Standard FAC-011-2(X) — System Operating Limits Methodology for the Operations Horizon**

- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

**C. Measures**

- M1.** The Reliability Coordinator’s SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

**1.2. Compliance Monitoring Period and Reset Time Frame**

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

**1.3. Data Retention**

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

**1.4. Additional Compliance Information**



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The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

- 1.4.1 SOL Methodology.
  - 1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)
  - 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
  - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
2. **Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology  
(Retirement approved by FERC effective January 21, 2014.)
  - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
  - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
  - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

**Standard FAC-011-2(X) — System Operating Limits Methodology for the Operations Horizon**

**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |

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| Requirement   | Lower   | Moderate  | High  | Severe   |
|---|---|---|---|--|
|   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>   |
| <p>R5<br/>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

### Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a [Remedial Action Scheme](#) to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

Deleted: Special Protection System

**Standard FAC-011-2(X) — System Operating Limits Methodology for the Operations Horizon**

**1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.

**1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

**1.3.1** Cascading does not occur.

**1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version     | Date              | Action  | Change Tracking   |
|-------------|-------------------|---|---|
| 1           | November 1, 2006  | Adopted by Board of Trustees  | New   |
| 2           |                   | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised   |
| 2           | June 24, 2008     | Adopted by Board of Trustees: FERC Order 705  | Revised   |
| 2           | January 22, 2010  | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update  |
| 2           | February 7, 2013  | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |   |
| 2           | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |   |
| 2           | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.   |   |
| <u>2(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-3.1a(X)
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Transmission Service Providers.
  - 4.5. Generator Operators.
  - 4.6. Load-Serving Entities.
  - 4.7. Purchasing-Selling Entities.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
  - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.
  - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.4. System real and reactive reserves (actual versus required).
  - R1.5. Capacity and energy adequacy conditions.
  - R1.6. Current ACE for all its Balancing Authorities.

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

- R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

**C. Measures**

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance



outages with Transmission Operators, Balancing Authorities and Generator Operators.  
(Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

## **D. Compliance**

### **1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

**1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

None.

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

**2. Violation Severity Levels:**

| Requirement | Lower   | Moderate  | High  | Severe  |
|-------------|---|---|---|---|
| R1          | The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.   | The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. | The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. | The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. |
| R1.1        | The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.  | N/A   | N/A   | N/A   |
| R1.2        | The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A   | N/A   | N/A   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower  | Moderate | High | Severe |
|-------------|--|----------|------|--------|
| R1.3        | The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A      | N/A  | N/A    |
| R1.4        | The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).  | N/A      | N/A  | N/A    |
| R1.5        | The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.   | N/A      | N/A  | N/A    |
| R1.6        | The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.   | N/A      | N/A  | N/A    |
| R1.7        | The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.   | N/A      | N/A  | N/A    |
| R1.8        | The Reliability Coordinator failed to monitor planned generation dispatches.   | N/A      | N/A  | N/A    |
| R1.9        | The Reliability Coordinator failed to monitor planned transmission or generation outages.  | N/A      | N/A  | N/A    |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower   | Moderate   | High  | Severe  |
|-------------|---|--|---|---|
| R1.10       | The Reliability Coordinator failed to monitor contingency events. | N/A  | N/A   | N/A   |
| R2          | N/A   | The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. | The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.  | The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. |
| R3          | N/A   | N/A  | The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans. | The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.  |
| R4          | N/A   | N/A  | N/A   | The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate | High  | Severe  |
|-------------|-------|----------|---|---|
| R5          | N/A   | N/A      | The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance. | The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition. |

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High  | Severe   |
|-------------|-------|--|---|--|
| R6          | N/A   | <p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real-time reliability analysis time frame or the next-day reliability analysis</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> |
| R7          | N/A   | N/A  | N/A   | <p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>   |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
| R8          | N/A   | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS. | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority. | The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.  |
| R9          | N/A   | N/A  | N/A  | The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Remedial Action Scheme that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected. |



**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
| R10         | N/A   | N/A  | N/A  | The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.   |
| R11         | N/A   | N/A  | N/A  | The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.  |
| R12         | N/A   | The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated. | N/A  | The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities. |

**E. Regional Differences**

None identified.

**Version History**

| Version | Date               | Action  | Change Tracking |
|---------|--------------------|---|-----------------|
| 0       | April 1, 2005      | Effective Date  | New             |
| 0       | August 8, 2005     | Removed “Proposed” from Effective Date  | Errata          |
| 1       |                    | Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17<br>Retired M2 and M3; modified M9 and M12; retired M13<br>Made conforming changes to data retention<br>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)<br>Retired VSLs associated with R2, R3, R5, R16 and R17;<br>Modified VSLs associated with R9 and R13, and R14 | Revised         |
| 2       | November 1, 2006   | Approved by the Board of Trustees   |                 |
| 2       | January 1, 2007    | Effective Date  |                 |
| 2a      | November 5, 2009   | Approved by the Board of Trustees   |                 |
| 3       | October 17, 2008   | Approved by the Board of Trustees   |                 |
| 3       | March 17, 2011     | Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)   |                 |
| 3a      | April 21, 2011     | Added FERC approved Interpretation  |                 |
| 3.1a    | March 8, 2012      | Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)  | Errata          |
| 3.1a    | September 13, 2012 | FERC approved   | Errata          |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

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|         |                   |   |  |
|---------|-------------------|---|--|
| 3.1a    | February 28, 2014 | Updated VSLs based on June 24, 2013 approval. |  |
| 3.1a(X) | TBD               | Adopted by the NERC Board of Trustees         | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Appendix 1

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3</b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0(X) “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p style="text-align: center;"><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12<sup>1</sup></b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation  |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>   |

<sup>1</sup> In the current version of the Standard (IRO-005-3a)(X), this requirement is R9.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

### A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-3.1a(X)
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Transmission Service Providers.
  - 4.5. Generator Operators.
  - 4.6. Load-Serving Entities.
  - 4.7. Purchasing-Selling Entities.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
  - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.
  - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.4. System real and reactive reserves (actual versus required).
  - R1.5. Capacity and energy adequacy conditions.
  - R1.6. Current ACE for all its Balancing Authorities.

**Deleted:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.¶  
In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.¶

**Deleted:** Special Protection System

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

Deleted: Special Protection System

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## Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

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**R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

### C. Measures

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance



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outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes. (Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

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### D. Compliance

#### 1. Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

**1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

None.

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**2. Violation Severity Levels:**

| Requirement | Lower   | Moderate  | High  | Severe  |
|-------------|---|---|---|---|
| R1          | The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.   | The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. | The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. | The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10. |
| R1.1        | The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.  | N/A   | N/A   | N/A   |
| R1.2        | The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. | N/A   | N/A   | N/A   |

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**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower  | Moderate | High | Severe |
|-------------|--|----------|------|--------|
| R1.3        | The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. | N/A      | N/A  | N/A    |
| R1.4        | The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).  | N/A      | N/A  | N/A    |
| R1.5        | The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.   | N/A      | N/A  | N/A    |
| R1.6        | The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.   | N/A      | N/A  | N/A    |
| R1.7        | The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.   | N/A      | N/A  | N/A    |
| R1.8        | The Reliability Coordinator failed to monitor planned generation dispatches.   | N/A      | N/A  | N/A    |
| R1.9        | The Reliability Coordinator failed to monitor planned transmission or generation outages.  | N/A      | N/A  | N/A    |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower   | Moderate   | High  | Severe  |
|-------------|---|--|---|---|
| R1.10       | The Reliability Coordinator failed to monitor contingency events. | N/A  | N/A   | N/A   |
| R2          | N/A   | The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. | The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.  | The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. |
| R3          | N/A   | N/A  | The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans. | The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.  |
| R4          | N/A   | N/A  | N/A   | The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.   |

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| Requirement | Lower | Moderate | High  | Severe  |
|-------------|-------|----------|---|---|
| R5          | N/A   | N/A      | The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance. | The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition. |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
| R6          | N/A   | <p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real- time reliability analysis time frame or the next-day reliability analysis</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real- time and next-day reliability analysis timeframes.</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real- time and next-day reliability analysis timeframes.</p> |
| R7          | N/A   | N/A   | N/A  | <p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>  |

**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
| R8          | N/A   | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS. | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority. | The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.  |
| R9          | N/A   | N/A  | N/A  | The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a <u>Remedial Action Scheme</u> that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the <u>Remedial Action Scheme</u> including any degradation or potential failure to operate as expected. |

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**Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
| R10         | N/A   | N/A  | N/A  | The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.   |
| R11         | N/A   | N/A  | N/A  | The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.  |
| R12         | N/A   | The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated. | N/A  | The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities. |

**E. Regional Differences**

None identified.

**Version History**

| Version | Date               | Action  | Change Tracking |
|---------|--------------------|---|-----------------|
| 0       | April 1, 2005      | Effective Date  | New             |
| 0       | August 8, 2005     | Removed “Proposed” from Effective Date  | Errata          |
| 1       |                    | Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17<br>Retired M2 and M3; modified M9 and M12; retired M13<br>Made conforming changes to data retention<br>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)<br>Retired VSLs associated with R2, R3, R5, R16 and R17;<br>Modified VSLs associated with R9 and R13, and R14 | Revised         |
| 2       | November 1, 2006   | Approved by the Board of Trustees   |                 |
| 2       | January 1, 2007    | Effective Date  |                 |
| 2a      | November 5, 2009   | Approved by the Board of Trustees   |                 |
| 3       | October 17, 2008   | Approved by the Board of Trustees   |                 |
| 3       | March 17, 2011     | Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)   |                 |
| 3a      | April 21, 2011     | Added FERC approved Interpretation  |                 |
| 3.1a    | March 8, 2012      | Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)  | Errata          |
| 3.1a    | September 13, 2012 | FERC approved   | Errata          |

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|                |                   |   |   |
|----------------|-------------------|---|---|
| 3.1a           | February 28, 2014 | Updated VSLs based on June 24, 2013 approval. |   |
| <u>3.1a(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Appendix 1

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3</b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0(X) “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded Remedial Action Schemes</u>. [Underline added for emphasis.]</i></p>  |
| <p><b>IRO-005-1 Requirement R12<sup>1</sup></b></p> <p><b>R12.</b> Whenever a <u>Remedial Action Scheme</u> that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that <u>Remedial Action Scheme</u> on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the <u>Remedial Action Scheme</u> including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p>   |
| <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a <u>RAS</u> shall have a documented Regional Reliability Organization <u>RAS</u> review procedure to ensure that <u>RAS</u> comply with Regional criteria and NERC Reliability Standards. The Regional <u>RAS</u> review procedure shall include:</p> <p><b>R1.3.</b> Requirements to demonstrate that the <u>RAS</u> shall be designed so that a single <u>RAS</u> component failure, when the <u>RAS</u> was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p>  |
| <p><b>Background Information for Interpretation</b></p> <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p> |

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<sup>1</sup> In the current version of the Standard (IRO-005-3a)(X), this requirement is R9.

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listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

**Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

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## A. Introduction

1. **Title:** Rated System Path Methodology
2. **Number:** MOD-029-1a(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1. Includes at least:
      - R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

- R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.
  - R1.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
  - R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).
  - R1.1.5.** Uses Load forecast by Balancing Authority.
  - R1.1.6.** Uses Transmission Facility additions and retirements.
  - R1.1.7.** Uses Generation Facility additions and retirements.
  - R1.1.8.** Uses Remedial Action Scheme (RAS) models where currently existing or projected for implementation within the studied time horizon.
  - R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
  - R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.
- R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R2.** The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R2.1.** Except where otherwise specified within MOD-029-1(X), adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:
    - R2.1.1.** When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
    - R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
    - R2.1.3.** Uncontrolled separation shall not occur.
  - R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Remedial Action Scheme (RAS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a RAS.

- R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.
- R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.
- R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.
- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

NL<sub>F</sub> is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native



Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

### C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1(X) and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |

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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

**Standard MOD-029-1a(X) — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |



**Version History**

| Version | Date                         | Action   | Change Tracking  |
|---------|------------------------------|--|--|
| 1       | 8/26/2008                    | Adopted by NERC Board of Trustees                |  |
| 1a      | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)  |
| 1a      | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |  |
| 1a(X)   | TBD                          | Adopted by the NERC Board of Trustees            | Replaced references to<br>Special Protection<br>System and SPS with<br>Remedial Action Scheme<br>and RAS |

## Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> <li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li> <li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li> <li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li> </ul> <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> <li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li> <li><b>R8.2.</b> Daily values, once per day.</li> <li><b>R8.3.</b> Monthly values, once per week.</li> </ul> |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>   |

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01(X) Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL<sub>F</sub> is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS<sub>F</sub> is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF<sub>F</sub> is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP<sub>F</sub> is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR<sub>F</sub> is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS<sub>F</sub> is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS<sub>NF</sub> is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_{NF}$  is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_{NF}$  is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

$OS_{NF}$  is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could  $OS_F$  in MOD-029-1(X) Requirement R5 and  $OS_{NF}$  in MOD-029-1(X) Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## Standard MOD-029-1a(X)— Rated System Path Methodology

### A. Introduction

1. **Title:** Rated System Path Methodology
2. **Number:** MOD-029-1a(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**Deleted: Proposed**

**Deleted:** Immediately after approval of applicable regulatory authorities.

### B. Requirements

- R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1. Includes at least:
      - R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

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- R1.1.2.** Models all system Elements as in-service for the assumed initial conditions.
  - R1.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
  - R1.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).
  - R1.1.5.** Uses Load forecast by Balancing Authority.
  - R1.1.6.** Uses Transmission Facility additions and retirements.
  - R1.1.7.** Uses Generation Facility additions and retirements.
  - R1.1.8.** Uses **Remedial Action Scheme (RAS)** models where currently existing or projected for implementation within the studied time horizon.
  - R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
  - R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.
  - R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R2.** The Transmission Operator shall use the following process to determine TTC:  
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R2.1.** Except where otherwise specified within MOD-029-1(X), adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:
    - R2.1.1.** When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
    - R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
    - R2.1.3.** Uncontrolled separation shall not occur.
  - R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a **Remedial Action Scheme (RAS)**, set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a **RAS**.

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- R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.
- R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.
- R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.
- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

NL<sub>F</sub> is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native

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Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$



**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

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### C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1(X) and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

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originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

Regional Entity.

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

##### 1.3. Data Retention

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

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- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

### **1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

### **1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |

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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |

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**Version History**

| Version      | Date                         | Action   | Change Tracking   |
|--------------|------------------------------|--|---|
| 1            | 8/26/2008                    | Adopted by NERC Board of Trustees                |   |
| 1a           | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)   |
| 1a           | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |   |
| <u>1a(X)</u> | <u>TBD</u>                   | <u>Adopted by the NERC Board of Trustees</u>     | <u>Replaced references to<br/>Special Protection<br/>System and SPS with<br/>Remedial Action Scheme<br/>and RAS</u> |



Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"><li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li><li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li><li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li></ul>  |
| <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"><li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li><li><b>R8.2.</b> Daily values, once per day.</li><li><b>R8.3.</b> Monthly values, once per week.</li></ul>  |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p> |

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The second part of NYISO's question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01(X) Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments ( $ETC_F$ ) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NL_F$  is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$  is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_F$  is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_F$  is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$ROR_F$  is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$OS_F$  is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ( $ETC_{NF}$ ) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$  is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

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GF<sub>NF</sub> is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP<sub>NF</sub> is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS<sub>NF</sub> is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could OS<sub>F</sub> in MOD-029-1(X) Requirement R5 and OS<sub>NF</sub> in MOD-029-1(X) Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** **MOD-030-02(X)**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3. The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a

minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

**R2.1.1.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

**R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

**R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

**R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

**R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor

(PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or

- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
  - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.
- R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.
- R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
  - If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
  - If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the sink.
  - If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.
  - If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
  - If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R5.1.** Use the models provided by the Transmission Operator.
  - R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider’s area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.
  - R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.
- R6.** When calculating the impact of ETC for firm commitments (ETC<sub>Fi</sub>) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:
  - R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
  - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.



Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

- R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC<sub>NFi</sub>) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

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<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{SFi} + counterflows_{Fi}$$

**Where:**

**AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{SNFi} + counterflows$$

**Where:**

**AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.
- R10.2.** For daily AFC, once per day.
- R10.3.** For monthly AFC, once per week.
- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

**C. Measures**

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

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<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)
- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)
- M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)
- M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.

- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |



| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>   | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>  |

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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>• The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>• The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |

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| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| <b>Version</b> | <b>Date</b> | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------|---|--|
| 2              |             | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised  |
| 2(X)           | TBD         | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard MOD-030-02(X) — Flowgate Methodology

### A. Introduction

1. **Title:** Flowgate Methodology
2. **Number:** MOD-030-02(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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### B. Requirements

- R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3. The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a

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minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.

**R2.1.1.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

Deleted: Special Protection System

**R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

**R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

Deleted: Special Protection System

**R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

**R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor

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(PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or

- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.
- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

**R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.

**R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

**R2.4.** Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

**R2.5.** At a minimum, establish the TFC once per calendar year.

**R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

**R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

**R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

**R3.3.** Updated at least once per month for AFC calculations for months two through 13.

**R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.

**R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

**R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
  - If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
  - If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
  - If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
  - If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
  - If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R5.1.** Use the models provided by the Transmission Operator.
  - R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.
  - R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.
- R6.** When calculating the impact of ETC for firm commitments ( $ETC_{Fi}$ ) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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- R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:
  - R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
  - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

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Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.

- R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC<sub>NFI</sub>) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.

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<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

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- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

- AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.
- TFC** is the Total Flowgate Capability of the Flowgate.
- ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.
- CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.
- TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.
- Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.
- counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

- AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.
- TFC** is the Total Flowgate Capability of the Flowgate.
- ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.
- ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.
- CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.
- TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.
- Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.
- counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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- R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.
- R10.2.** For daily AFC, once per day.
- R10.3.** For monthly AFC, once per week.
- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$\begin{aligned} \text{ATC} &= \min(P) \\ P &= \{\text{PATC}_1, \text{PATC}_2, \dots, \text{PATC}_n\} \\ \text{PATC}_n &= \frac{\text{AFC}_n}{\text{DF}_{np}} \end{aligned}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

### C. Measures

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)

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<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

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- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)
- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

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- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)
- M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)
- M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

Regional Entity.

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

##### 1.3. Data Retention

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.

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- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

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**2. Violation Severity Levels**

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |

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| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than   | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than  | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than   | The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or   |

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| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |

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| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

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**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| Version         | Date           | Action  | Change Tracking   |
|-----------------|----------------|---|---|
| 2               |                | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised   |
| <del>2(X)</del> | <del>TBD</del> | <del>Adopted by the NERC Board of Trustees</del>  | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |

Deleted: Adopted by NERC Board of Trustees: February 10, 2009

**A. Introduction**

- 1. Title:** Nuclear Plant Interface Coordination
- 2. Number:** NUC-001-2.1(X)
- 3. Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
- 4. Applicability:**
  - 4.1.** Nuclear Plant Generator Operator.
  - 4.2.** Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
    - 4.2.1** Transmission Operators.
    - 4.2.2** Transmission Owners.
    - 4.2.3** Transmission Planners.
    - 4.2.4** Transmission Service Providers.
    - 4.2.5** Balancing Authorities.
    - 4.2.6** Reliability Coordinators.
    - 4.2.7** Planning Coordinators.
    - 4.2.8** Distribution Providers.
    - 4.2.9** Load-serving Entities.
    - 4.2.10** Generator Owners.
    - 4.2.11** Generator Operators.
- 5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1.** The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements<sup>1</sup> that include mutually agreed to NPIRs and document how the

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1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]

- R3.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]
- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
  - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
  - R4.2.** Operate the electric system to meet the NPIRs.
  - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
  - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
  - R9.2.** Technical requirements and analysis:
    - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.

- R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
- R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
- R9.3.** Operations and maintenance coordination:
  - R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
  - R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
  - R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
  - R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
  - R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
  - R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
  - R9.3.7.** Coordination of the NPIRs with transmission system Remedial Action Schemes and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
  - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
  - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
  - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
  - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
  - R9.4.5.** Provisions for personnel training, as related to NPIRs.

**C. Measures**

- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)
- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
  - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
  - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
  - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

#### **D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Enforcement Authority**

Regional Entity.
  - 1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.
  - 1.3. Compliance Monitoring and Enforcement Processes:**

Compliance Audits  
Self-Certifications  
Spot Checking  
Compliance Violation Investigations  
Self-Reporting  
Complaints

#### **1.4. Data Retention**

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

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

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

#### **1.5. Additional Compliance Information**

None.

### **2. Violation Severity Levels**

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

### **E. Regional Differences**

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory

## Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

**Nuclear Plant Licensing Requirements (NPLR)** are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

### F. Associated Documents

#### Version History

| Version | Date              | Action   | Change Tracking                           |
|---------|-------------------|--|---|
| 1       | May 2, 2007       | Approved by Board of Trustees  | New                                       |
| 2       | To be determined  | Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.                             | Revision                                  |
| 2       | August 5, 2009    | Adopted by Board of Trustees   | Revised                                   |
| 2       | January 22, 2010  | Approved by FERC on January 21, 2010<br>Added Effective Date   | Update                                    |
| 2       | February 7, 2013  | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. |   |
| 2.1     | April 11, 2012    | Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)                   | Errata associated with Project 2007-17    |
| 2.1     | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.   |   |
| 2.1     | November 21, 2013 | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)   |   |
| 2.1(X)  | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection |

**Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination**

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|  |  |  | System and SPS with Remedial Action Scheme and RAS |
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## Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

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### A. Introduction

1. **Title:** Nuclear Plant Interface Coordination
2. **Number:** NUC-001-2.1(X)
3. **Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
4. **Applicability:**
  - 4.1. Nuclear Plant Generator Operator.
  - 4.2. Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
    - 4.2.1 Transmission Operators.
    - 4.2.2 Transmission Owners.
    - 4.2.3 Transmission Planners.
    - 4.2.4 Transmission Service Providers.
    - 4.2.5 Balancing Authorities.
    - 4.2.6 Reliability Coordinators.
    - 4.2.7 Planning Coordinators.
    - 4.2.8 Distribution Providers.
    - 4.2.9 Load-serving Entities.
    - 4.2.10 Generator Owners.
    - 4.2.11 Generator Operators.
5. **Effective Date:** [This standard shall become effective on the first day of the first calendar quarter that is twelve \(12\) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve \(12\) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.](#)

Deleted: . April 1, 2010

### B. Requirements

- R1. The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements<sup>1</sup> that include mutually agreed to NPIRs and document how the

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1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

## Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

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Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]

- R3.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]
- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
  - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
  - R4.2.** Operate the electric system to meet the NPIRs.
  - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
  - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
  - R9.2.** Technical requirements and analysis:
    - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.

## Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

- R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
- R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
- R9.3.** Operations and maintenance coordination:
  - R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
  - R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
  - R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
  - R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
  - R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
  - R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
  - R9.3.7.** Coordination of the NPIRs with transmission system [Remedial Action Schemes](#) and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
  - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
  - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
  - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
  - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
  - R9.4.5.** Provisions for personnel training, as related to NPIRs.

Deleted: Special Protection System

### C. Measures

## Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

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- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)
- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
  - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
  - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
  - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

### D. Compliance

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Enforcement Authority**

Regional Entity.
  - 1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.
  - 1.3. Compliance Monitoring and Enforcement Processes:**

## Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

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Compliance Audits  
Self-Certifications  
Spot Checking  
Compliance Violation Investigations  
Self-Reporting  
Complaints

### 1.4. Data Retention

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

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

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

### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

## E. Regional Differences

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory

**Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination**

requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

**Nuclear Plant Licensing Requirements (NPLR)** are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

**F. Associated Documents**

**Version History**

| Version       | Date              | Action   | Change Tracking                                  |
|---------------|-------------------|--|--|
| 1             | May 2, 2007       | Approved by Board of Trustees  | New  |
| 2             | To be determined  | Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.                             | Revision   |
| 2             | August 5, 2009    | Adopted by Board of Trustees   | Revised  |
| 2             | January 22, 2010  | Approved by FERC on January 21, 2010<br>Added Effective Date   | Update   |
| 2             | February 7, 2013  | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. |  |
| 2.1           | April 11, 2012    | Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)                   | Errata associated with Project 2007-17           |
| 2.1           | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.   |  |
| 2.1           | November 21, 2013 | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)   |  |
| <u>2.1(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection</u> |

**Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination**

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|  |  |  | <u>System and SPS with<br/>Remedial Action<br/>Scheme and RAS</u> |
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## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(X)
3. **Purpose:**  
To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.



- R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:
  - R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
  - R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

### **C. Measures**

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 6 Part 2)

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

##### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

## **2. Levels of Non-Compliance for Generator Operators:**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

## **3. Levels of Non-Compliance for Transmission Operators:**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

3.3. **Level 3:** Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. **Levels of Non-Compliance for Balancing Authorities:**

4.1. **Level 1:** Not applicable.

4.2. **Level 2:** Not applicable.

4.3. **Level 3:** Not applicable.

4.4. **Level 4:** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**E. Regional Differences**

None identified.

**Version History**

| Version | Date              | Action  | Change Tracking                           |
|---------|-------------------|---|---|
| 0       | April 1, 2005     | Effective Date  | New                                       |
| 0       | August 8, 2005    | Removed “Proposed” from Effective Date  | Errata                                    |
| 0       | August 25, 2005   | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata                                    |
| 1       | November 1, 2006  | Adopted by Board of Trustees  | Revised                                   |
| 1.1     | April 11, 2012    | Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”) | Errata associated with Project 2007-17    |
| 1.1     | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.  |   |
| 1.1(X)  | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection |

**Standard PRC-001-1.1(X) — System Protection Coordination**

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|--|--|--|--|
|  |  |  | System and SPS with Remedial Action Scheme and RAS |
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## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(X)
3. **Purpose:**  
To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: January 1, 2007 .

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:
  - R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
  - R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Deleted: Special Protection System

**C. Measures**

- M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 6 Part 2)

Deleted: Special Protection System

Deleted: Special Protection System

**D. Compliance**

- 1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.
  - 1.2. **Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance for Generator Operators:**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

**3. Levels of Non-Compliance for Transmission Operators:**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

**Standard PRC-001-1.1(X) — System Protection Coordination**

3.3. **Level 3:** Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

Deleted: Special Protection System

**4. Levels of Non-Compliance for Balancing Authorities:**

4.1. **Level 1:** Not applicable.

4.2. **Level 2:** Not applicable.

4.3. **Level 3:** Not applicable.

4.4. **Level 4:** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

Deleted: Special Protection System

**E. Regional Differences**

None identified.

**Version History**

| Version       | Date              | Action  | Change Tracking                                  |
|---------------|-------------------|---|--|
| 0             | April 1, 2005     | Effective Date  | New  |
| 0             | August 8, 2005    | Removed "Proposed" from Effective Date  | Errata   |
| 0             | August 25, 2005   | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata   |
| 1             | November 1, 2006  | Adopted by Board of Trustees  | Revised  |
| 1.1           | April 11, 2012    | Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System") | Errata associated with Project 2007-17           |
| 1.1           | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.  |  |
| <u>1.1(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection</u> |



**Standard PRC-001-1.1(X) — System Protection Coordination**

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|--|--|--|---|
|  |  |  | <u>System and SPS with Remedial Action Scheme and RAS</u> |
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**A. Introduction**

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-1(X)
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

**4. Applicability**

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.

- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:
- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
- R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
- R2.3.2.** When FERAS is not available, then
- 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
- 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
- R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any

Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

- R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Assessment*]
- R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Assessment*]
  - R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
  - R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

### **C. Measures**

**Each measure below applies directly to the requirement by number.**

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
  - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
  - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
  - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
  - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
    - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
  - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
    - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

**M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.

**M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

**R1**

|              |                 |             |               |
|--------------|-----------------|-------------|---------------|
| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

|   |   |  |  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |
|---|---|--|--|

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.2.2 and R2.4**

| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|
|              |                 |             |               |

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

|  |   |   |  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |
|--|---|---|--|

**R3.1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| <b>Version</b> | <b>Date</b>    | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|----------------|--|------------------------|
| 1              | April 16, 2008 | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1 |                        |

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

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|      |                |   |  |
|------|----------------|---|--|
| 1    | April 21, 2011 | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |  |
| 1(X) | TBD            | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

**A. Introduction**

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-1(X)
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

**4. Applicability**

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.

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

**Deleted:** On the first day of the second quarter following applicable regulatory approval.

**B. Requirements**

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.

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**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

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**R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

**R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

**R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

**R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.

**R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.

**R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

**R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.

**R2.3.2.** When FERAS is not available, then

**2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or

**2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.

**R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.

**R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any

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**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

**R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

**R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

**R3.1.** Identification of a Misoperation of a Protection System and/or RAS,

**R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

**C. Measures**

**Each measure below applies directly to the requirement by number.**

**M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

**M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.

**M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.

**M2.** Transmission Owners and Generation Owners shall have evidence for the following.

**M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

**M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.

**M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

**M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.

**M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.

**M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.

**M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

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- M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
  - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.
  - M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.
- M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.
  - M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.
  - M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

**R1**

|              |                 |             |               |
|--------------|-----------------|-------------|---------------|
| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|

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|   |   |  |  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |
|---|---|--|--|

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.2.2 and R2.4**

| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|
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|  |   |   |  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |
|--|---|---|--|

**R3.1**

| Lower   | Moderate  | High  | Severe  |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| Lower   | Moderate  | High  | Severe  |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| Version | Date           | Action   | Change Tracking |
|---------|----------------|--|-----------------|
| 1       | April 16, 2008 | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1 |                 |

Deleted: Adopted by Board of Trustees: October 29, 2008

**WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation**

|             |                |   |   |
|-------------|----------------|---|---|
| 1           | April 21, 2011 | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |   |
| <u>1(X)</u> | <u>TBD</u>     | <u>Adopted by the NERC Board of Trustees</u>                                  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Deleted: Adopted by Board of Trustees: October 29, 2008

## A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. (See the Implementation Plan for additional detail)



## B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**Component Type** - Any one of the five specific elements of the Protection System definition.

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

**Component** – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

**Unresolved Maintenance Issue** - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium]*  
*[Time Horizon: Operations Planning]*

## **C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## **D. Compliance**

- 1. Compliance Monitoring Process**
- 1.1. Compliance Enforcement Authority**  
Regional Entity
- 1.2. Compliance Monitoring and Enforcement Processes:**  
Compliance Audit  
Self-Certification  
Spot Checking  
Compliance Investigation  
Self-Reporting  
Complaint

### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|--------------------|---|---|--|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,</li> </ul> </li> </ol> <p style="text-align: center;">OR</p> |

**Standard PRC-005-2(X) — Protection System Maintenance**

| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,</li> <li style="text-align: center;">OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>   |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or   | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10   | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15   | The responsible entity failed to undertake efforts to correct greater   |

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| Requirement Number | Lower VSL                                       | Moderate VSL                              | High VSL                                  | Severe VSL  |
|--------------------|---|---|---|---|
|                    | fewer identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(X) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |



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|      |                   |  |  |
|------|-------------------|--|--|
| 1.1b | May 9, 2012       | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).   |  |
| 2    | November 7, 2012  | Adopted by Board of Trustees   | Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2    | October 17, 2013  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.  |  |
| 2    | December 19, 2013 | FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. |  |
| 2(X) | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS           |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 calendar years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |



| <b>Table 1-4(b)</b><br><b>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |   |   |
|---|---|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).                       |   |   |
| Component Attributes  | Maximum Maintenance Interval                  | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|   | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|   | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|   | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |





| <b>Table 1-4(c)</b><br><b>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).              |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <b>Table 1-4(d)</b><br><b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).              |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RASs except as noted.</b> |                                   |   |
|--|-----------------------------------|---|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.   | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.   | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 calendar years             | <p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 calendar years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 calendar years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |



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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**Segment** – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

**Countable Event** – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## Standard PRC-005-2(X) — Protection System Maintenance

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### A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. (See the [Implementation Plan for additional detail](#))

Deleted: Special Protection System (SPS)

Deleted: See Implementation Plan

## Standard PRC-005-2(X) — Protection System Maintenance

### B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**Component Type** - Any one of the five specific elements of the Protection System definition.

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
  - 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

**Component** – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

**Unresolved Maintenance Issue** - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Standard PRC-005-2(X) — Protection System Maintenance**

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- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. [*Violation Risk Factor: Medium*]  
[*Time Horizon: Operations Planning*]

## Standard PRC-005-2(X) — Protection System Maintenance

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### C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Enforcement Authority**
    - Regional Entity
  - 1.2. **Compliance Monitoring and Enforcement Processes:**
    - Compliance Audit
    - Self-Certification
    - Spot Checking
    - Compliance Investigation
    - Self-Reporting
    - Complaint

## Standard PRC-005-2(X) — Protection System Maintenance

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### 1.3. Evidence Retention

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

### 1.4. Additional Compliance Information

None.



**Standard PRC-005-2(X) — Protection System Maintenance**

**2. Violation Severity Levels**

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|--------------------|---|---|--|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to:             <ul style="list-style-type: none"> <li>• Annually update the list of Components,</li> </ul> </li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>Annually perform maintenance on the greater of 5% of the segment population or 3 Components,</li> </ul> <p style="text-align: center;">OR</p> <ul style="list-style-type: none"> <li>Annually analyze the program activities and results for each Segment.</li> </ul>  |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or   | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10   | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15   | The responsible entity failed to undertake efforts to correct greater   |

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| Requirement Number | Lower VSL                                       | Moderate VSL                              | High VSL                                  | Severe VSL  |
|--------------------|---|---|---|---|
|                    | fewer identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | than 15 identified Unresolved Maintenance Issues. |

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**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(X) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

**Version History**

| Version | Date               | Action  | Change Tracking                |
|---------|--------------------|---|--------------------------------|
| 0       | April 1, 2005      | Effective Date  | New                            |
| 1       | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a      | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a      | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a      | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a    | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b      | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b    | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|             |                   |  |  |
|-------------|-------------------|--|--|
| 1.1b        | May 9, 2012       | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).   |  |
| 2           | November 7, 2012  | Adopted by Board of Trustees   | Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2           | October 17, 2013  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.  |  |
| 2           | December 19, 2013 | FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. |  |
| <u>2(X)</u> | <u>TBD</u>        | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>    |

**Standard PRC-005-2(X) – Protection System Maintenance**

**Table 1-1  
Component Type - Protective Relay  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
|--|---|---|
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

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**Table 1-1  
Component Type - Protective Relay  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes  | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities   |
|---|---|--|
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | <p align="center">12 calendar years</p>   | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p> |

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**Table 1-2  
Component Type - Communications Systems  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |



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| <b>Table 1-3<br/>                     Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                   | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified   | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for **RAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

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| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |



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Table 1-4(b)

Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for **RAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

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| Component Attributes   | Maximum Maintenance Interval                  | Maintenance Activities  |
|--|---|---|
| Protection System Station dc supply with <b>Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|  | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br><br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |



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| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)                 |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for <u>RAS</u> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

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| <b>Table 1-4(d)</b><br><b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for <del>RAS</del> , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect: <ul style="list-style-type: none"> <li>• Condition of non-battery based dc supply</li> </ul>  |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

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| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for <u>RAS</u> , non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <u>RAS</u> , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

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| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

**Standard PRC-005-2(X) – Protection System Maintenance**

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RASs except as noted.</b> |                                   |   |
|--|-----------------------------------|---|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with <del>RAS</del> .   | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the <del>RAS</del> .   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or <del>RAS</del> whose integrity is monitored and alarmed (See Table 2).   | No periodic maintenance specified | None.   |

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**Standard PRC-005-2(X) – Protection System Maintenance**

| Table 2 – Alarming Paths and Monitoring   |                                   |  |
|---|-----------------------------------|--|
| In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements  |                                   |  |
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| <p>Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.</p> <p>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.</p> | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| <p>Alarm Path with monitoring:</p> <p>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.</p>   | No periodic maintenance specified | None.  |

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| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems  |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years             | Verify that settings are as specified<br>For non-microprocessor relays:<br><ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays:<br><ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following:<br><ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> Alarming for power supply failure (See Table 2).   | 12 calendar years            | Verify:<br><ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| Monitored microprocessor protective relay with preceding row attributes and the following:<br><ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> Alarming for change of settings (See Table 2). | 12 calendar years            | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.  |

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| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                 | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                 | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                 | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                 | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified | None.  |

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**Segment** – Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.

**Countable Event** – A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

**A. Introduction**

- 1. Title:**       **Protection System and Automatic Reclosing Maintenance**
- 2. Number:**     PRC-005-3(X)
- 3. Purpose:**    To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
  - 4.1. Functional Entities:**
    - 4.1.1**   Transmission Owner
    - 4.1.2**   Generator Owner
    - 4.1.3**   Distribution Provider
  - 4.2. Facilities:**
    - 4.2.1**   Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2**   Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3**   Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4**   Protection Systems installed as a Remedial Action Schemes (RAS) for BES reliability.
    - 4.2.5**   Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6**   Automatic Reclosing<sup>1</sup>, including:
      - 4.2.6.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.



gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

**4.2.6.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.6.3** Automatic Reclosing applied as an integral part of a RAS specified in Section 4.2.4.

**5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. (See the Implementation Plan for additional detail)

**6. Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

## **B. Requirements**

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
  - 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

## **C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

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For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

##### 1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting

Complaint

**1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

**1.4. Additional Compliance Information**

None.

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**2. Violation Severity Levels**

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|--------------------|---|---|---|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>  | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.    |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |



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|      |                  |   |  |
|------|------------------|---|--|
| 1.1b | May 9, 2012      | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).  |  |
| 2    | November 7, 2012 | Adopted by Board of Trustees  | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2    | October 17, 2013 | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing |  |
| 3    | November 7, 2013 | Adopted by the NERC Board of Trustees   | Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.              |
| 3(X) | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS                               |

| <b>Table 1-1<br/>                     Component Type - Protective Relay<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>   |   |   |
|--|---|---|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval<sup>2</sup></b> | <b>Maintenance Activities</b>   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                                | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                               | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| <b>Table 1-1<br/>                     Component Type - Protective Relay<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>   |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 Calendar Years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 Calendar Months            | Verify that the communications system is functional.   |
|   | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| <b>Table 1-3</b><br><b>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3) |                              |   |
|--|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |                              |   |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |



| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |   |   |
|---|---|---|
| Component Attributes  | Maximum Maintenance Interval                  | Maintenance Activities  |
|   | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| Table 1-4(d)<br>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|  | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|  | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5<br/>                     Component Type - Control Circuitry Associated With Protective Functions<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                                     |   |
|--|-------------------------------------|---|
| <b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.</b>  |                                     |   |
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>   |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 Calendar Years                    | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).              | 6 Calendar Years                    | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.<br>(See Table 4-2(b) for RAS which include Automatic Reclosing.)  | 12 Calendar Years                   | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 Calendar Years                   | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified   | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.  | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | <p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 Calendar Years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 Calendar Years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |



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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing Relay   |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |

**Table 4-2(a)**  
**Maintenance Activities and Intervals for Automatic Reclosing Components**  
**Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a RAS**

| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
|---|-----------------------------------|--|
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a RAS.  | 12 Calendar Years                 | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of a RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2) | No periodic maintenance specified | None.  |

| <b>Table 4-2(b)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of a RAS</b> |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of a RAS (regardless of any monitoring of the control circuitry).                        | 6 Calendar Years                    | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.                             |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of a RAS.   | 12 Calendar Years                   | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS. |
| Control circuitry associated with Automatic Reclosing that is an integral part of a RAS whose integrity is monitored and alarmed. (See Table 2)  | No periodic maintenance specified   | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## Standard PRC-005-3(X) — Protection System and Automatic Reclosing Maintenance

### A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-3(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a [Remedial Action Schemes \(RAS\)](#) for BES reliability.
    - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6 Automatic Reclosing<sup>1</sup>, including:
      - 4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

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gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

**4.2.6.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.6.3** Automatic Reclosing applied as an integral part of a RAS specified in Section 4.2.4.

Deleted: n SPS

**5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. (See the Implementation Plan for additional detail)

Deleted: See Implementation Plan

**6. Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

## Standard PRC-005-3(X) — Protection System and Automatic Reclosing Maintenance

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

### B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
  - 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

### C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.



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For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

##### 1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting

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Complaint

**1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

**1.4. Additional Compliance Information**

None.

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**2. Violation Severity Levels**

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|--------------------|---|---|---|--|
| R1                 | <p>The responsible entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>  | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,</li> <li>OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,</li> <li>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.              |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

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### E. Regional Variances

None

### F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

### Version History

| Version | Date               | Action  | Change Tracking                |
|---------|--------------------|---|--------------------------------|
| 0       | April 1, 2005      | Effective Date  | New                            |
| 1       | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a      | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a      | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a      | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a    | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b      | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b    | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

|             |                  |   |  |
|-------------|------------------|---|--|
| 1.1b        | May 9, 2012      | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).  |  |
| 2           | November 7, 2012 | Adopted by Board of Trustees  | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2           | October 17, 2013 | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing |  |
| 3           | November 7, 2013 | Adopted by the NERC Board of Trustees   | Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.              |
| <u>3(X)</u> | <u>TBD</u>       | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>                        |

**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

**Table 1-1  
Component Type - Protective Relay  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
|--|---|---|
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.



**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

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**Table 1-1  
Component Type - Protective Relay  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes  | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities   |
|---|---|--|
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | <p align="center">12 Calendar Years</p>   | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p> |

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**Table 1-2  
Component Type - Communications Systems  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
|--|------------------------------|--|
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.   | 4 Calendar Months            | Verify that the communications system is functional.   |
|  | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).  | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| <p>Any communications system with all of the following:</p> <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

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| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

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| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)          |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

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**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

**Table 1-4(a)  
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for [RAS](#), non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

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| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

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| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)                 |                              |   |
|--|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for <a href="#">RAS</a> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |   |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply with <b>Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |

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| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)                 |   |   |
|--|---|---|
| Protection System Station dc supply used only for non-BES interrupting devices for <a href="#">RAS</a> , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |   |   |
| Component Attributes   | Maximum Maintenance Interval                  | Maintenance Activities  |
|  | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

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| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

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| Table 1-4(d)<br>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|  | 18 Calendar Months           | Inspect: <ul style="list-style-type: none"> <li>• Condition of non-battery based dc supply</li> </ul>  |
|  | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

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| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for <u>RAS</u> , non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a <u>RAS</u> , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

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| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

| Table 1-5<br>Component Type - Control Circuitry Associated With Protective Functions<br>Excluding distributed UFLS and distributed UVLS (see Table 3)                                       |                                   |   |
|---|-----------------------------------|---|
| Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <u>RAS</u> except as noted.   |                                   |   |
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry). | 6 Calendar Years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with <u>RAS</u> .<br>(See Table 4-2(b) for <u>RAS</u> which include Automatic Reclosing.)  | 12 Calendar Years                 | Verify all paths of the control circuits essential for proper operation of the <u>RAS</u> .   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.   | 12 Calendar Years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or <u>RAS</u> whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified | None.   |

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**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.  | No periodic maintenance specified | None.  |

**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

**Table 3  
Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems**

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> Alarming for power supply failure (See Table 2).   | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> Alarming for change of settings (See Table 2). | 12 Calendar Years            | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.  |

**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

**Table 3  
Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems**

| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
|--|-----------------------------------|--|
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                 | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                 | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                 | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                 | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified | None.  |

**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

**Table 4-1  
Maintenance Activities and Intervals for Automatic Reclosing Components  
Component Type – Reclosing Relay**

| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
|--|------------------------------|--|
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |



**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

| Table 4-2(a)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a <a href="#">RAS</a> |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a <a href="#">RAS</a> .   | 12 Calendar Years                 | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of a <a href="#">RAS</a> and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)           | No periodic maintenance specified | None.  |

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**Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance**

| Table 4-2(b)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of a <b>RAS</b> |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of a <b>RAS</b> (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.                                     |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of a <b>RAS</b> .   | 12 Calendar Years                 | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the <b>RAS</b> . |
| Control circuitry associated with Automatic Reclosing that is an integral part of a <b>RAS</b> whose integrity is monitored and alarmed. (See Table 2)   | No periodic maintenance specified | None.  |

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**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-1(X)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
  - 4.1. Planning Coordinators
  - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - 4.2.1 Transmission Owners
    - 4.2.2 Distribution Providers
  - 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [*VRF: Medium*][*Time Horizon: Long-term Planning*]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [*VRF: Medium*][*Time Horizon: Long-term Planning*]
  - 2.1. Those islands selected by applying the criteria in Requirement R1, and

- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme, and
  - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
- 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
    - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
    - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
    - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the

- Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
  - 11.1.** The performance of the UFLS equipment,
  - 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance

with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

**R14.** Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

**14.1.** UFLS program, including a schedule for implementation

**14.2.** UFLS design assessment

**14.3.** Format and schedule of UFLS data submittal

### **C. Measures**

**M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

**M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

**M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.



- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a

UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity

#### **1.2. Data Retention**

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

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

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

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

Not applicable.

**2. Violation Severity Levels**

| R # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
| R1  | N/A       | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>   |
| R2  | N/A       | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p> |

| R #       | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
|-----------|--|---|--|--|
| <b>R3</b> | N/A  | <p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p> |
| <b>R4</b> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                        | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                     | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>   |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     |   |   |   | The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2                                 |
| R5  | N/A   | N/A   | N/A   | The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5. |
| R6  | N/A   | N/A   | N/A   | The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.  |
| R7  | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.<br>OR   |

| R #        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|------------|---|---|---|---|
|            |   |   |   | The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.  |
| <b>R8</b>  | The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.                | <p>The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.</p> <p>OR</p> <p>The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.</p> | The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | <p>The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.</p> <p>OR</p> <p>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.</p> |
| <b>R9</b>  | The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. | The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.  | The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.                  | The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.  |
| <b>R10</b> | The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching  | The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching   | The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching   | The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,  |

| R #               | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-------------------|---|--|--|---|
|                   | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>   | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  | <p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  | <p>Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>  |
| <p><b>R11</b></p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.</p> <p>OR</p> |



| R #        | Lower VSL | Moderate VSL   | High VSL   | Severe VSL   |
|------------|-----------|--|--|--|
|            |           |  | specified in Requirement R11, Parts 11.1 or 11.2.  | The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.  |
| <b>R12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.<br><br>OR<br>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies. |
| <b>R13</b> | N/A       | N/A  | N/A  | The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency  |

| R #        | Lower VSL | Moderate VSL | High VSL | Severe VSL   |
|------------|-----------|--------------|----------|--|
|            |           |              |          | excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13   |
| <b>R14</b> | N/A       | N/A          | N/A      | The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3. |

## E. Regional Variances

### E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

**E.A.3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).  
*[VRF: High][Time Horizon: Long-term Planning]*

**E.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**EA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

**EA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

**EA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

**E.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

**E.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1A, and

**E.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 2A, and

**E.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**M.E.A.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

**M.E.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

| E #        | Lower VSL | Moderate VSL  | High VSL   | Severe VSL  |
|------------|-----------|---|--|---|
| <b>EA3</b> | N/A       | The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to develop a UFLS program.  |
| <b>EA4</b> | N/A       | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3.<br><br>OR<br><br>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 |

## **E.B. Regional Variance for the Western Electricity Coordinating Council**

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

- E.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*
- E.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*
- E.B.2.1.** Those islands selected by applying the criteria in Requirement E.B.1, and
- E.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme.
- EB.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
- E.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
- E.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**E.B.11.1.** The performance of the UFLS equipment,

**E.B.11.2** The effectiveness of the UFLS program

**E.B.12.** Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

- M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.
- M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.
- M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.
- M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.
- M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.
- M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.



| E #   | Lower VSL | Moderate VSL   | High VSL  | Severe VSL   |
|-------|-----------|--|---|--|
| E.B.1 | N/A       | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p> |
| E.B.2 | N/A       | N/A  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>   |

| E #          | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|--------------|--|---|---|---|
|              |  |   |   | The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.  |
| <b>E.B.3</b> | N/A  | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area. |
| <b>E.B.4</b> | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island                      | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island                      | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island  |

| E #           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|---------------|---|--|--|--|
|               | <p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>  | <p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p> |
| <b>E.B.11</b> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>   |

| E #           | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|---------------|-----------|---|---|--|
|               |           |   | <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p> | <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> |
| <b>E.B.12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design   | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design  |

| E # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
|     |           | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p> |

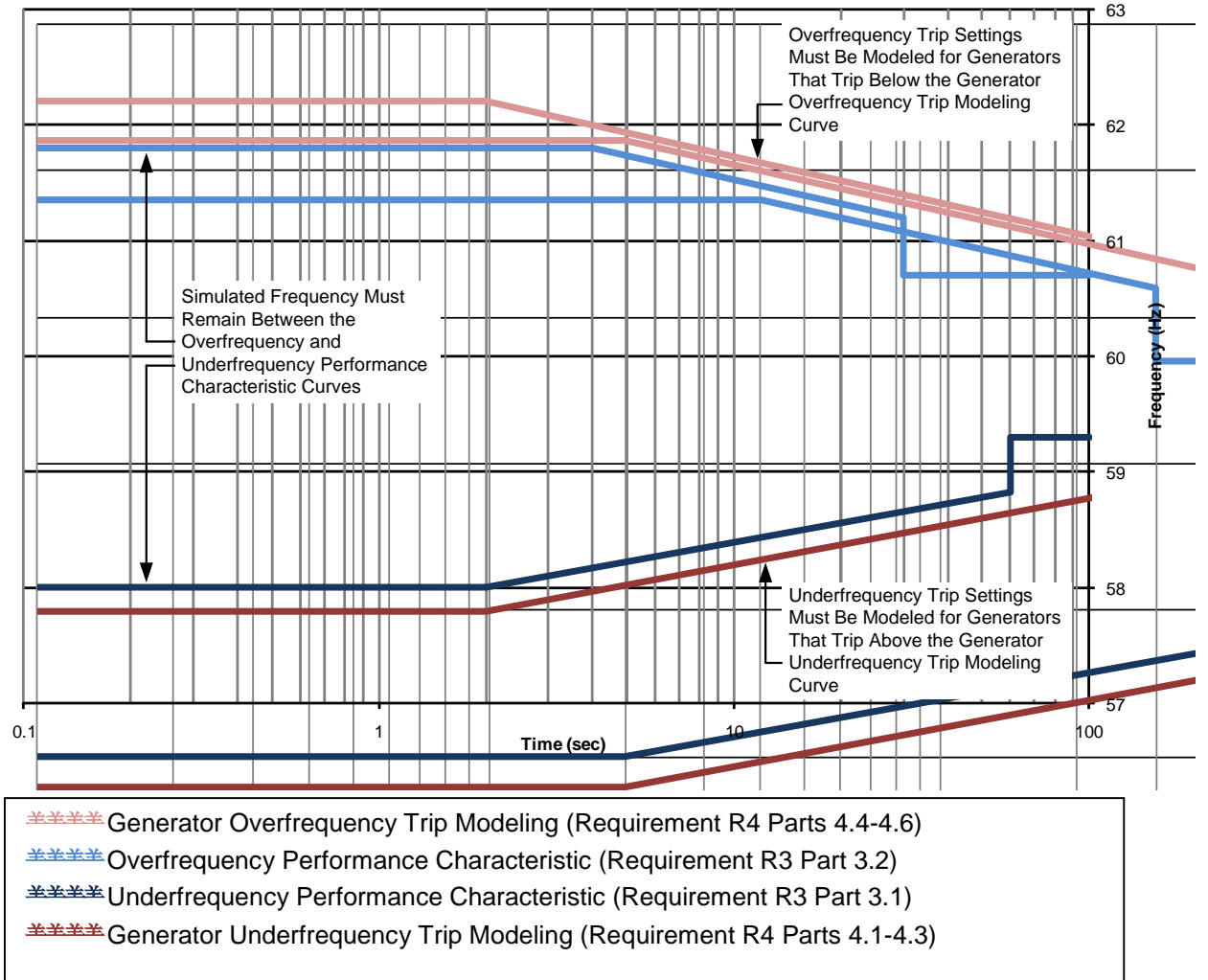
**Associated Documents**

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>  | <b>Change Tracking</b>   |
|----------------|------------------|--|--|
| 1              | May 25, 2010     | Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.   |  |
| 1              | November 4, 2010 | Adopted by the Board of Trustees   |  |
| 1              | May 7, 2012      | FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)   |  |
| 1              | November 9, 2012 | FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8. |  |
| 1(X)           | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## PRC-006-1(X) – Attachment 1

### Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



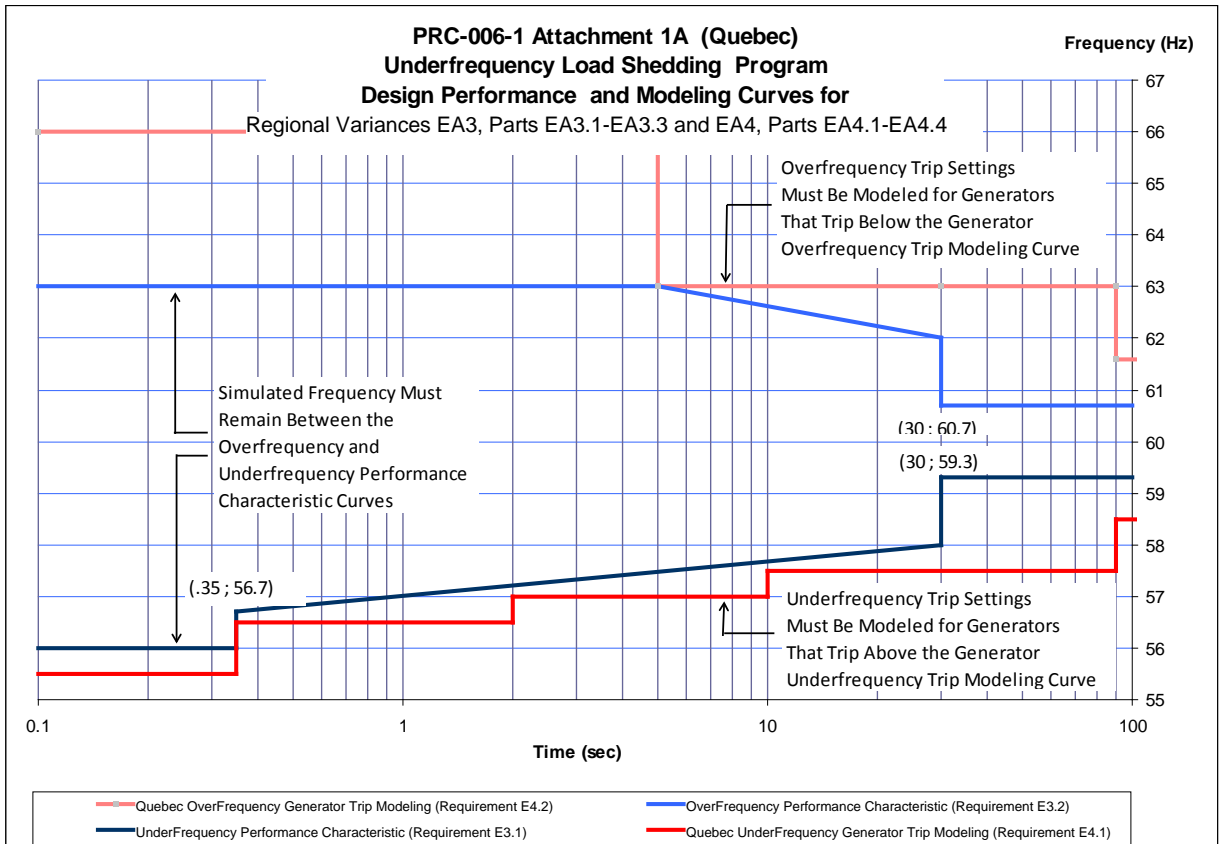
#### Curve Definitions

| Generator Overfrequency Trip Modeling |  | Overfrequency Performance Characteristic |  |                       |
|---------------------------------------|--|--|--|-----------------------|
| $t \leq 2 \text{ s}$                  | $t > 2 \text{ s}$                      | $t \leq 4 \text{ s}$                     | $4 \text{ s} < t \leq 30 \text{ s}$    | $t > 30 \text{ s}$    |
| $f = 62.2 \text{ Hz}$                 | $f = -0.686\log(t) + 62.41 \text{ Hz}$ | $f = 61.8 \text{ Hz}$                    | $f = -0.686\log(t) + 62.21 \text{ Hz}$ | $f = 60.7 \text{ Hz}$ |

| Generator Underfrequency Trip Modeling |                                       | Underfrequency Performance Characteristic |                                       |                       |
|--|---------------------------------------|---|---------------------------------------|-----------------------|
| $t \leq 2 \text{ s}$                   | $t > 2 \text{ s}$                     | $t \leq 2 \text{ s}$                      | $2 \text{ s} < t \leq 60 \text{ s}$   | $t > 60 \text{ s}$    |
| $f = 57.8 \text{ Hz}$                  | $f = 0.575\log(t) + 57.63 \text{ Hz}$ | $f = 58.0 \text{ Hz}$                     | $f = 0.575\log(t) + 57.83 \text{ Hz}$ | $f = 59.3 \text{ Hz}$ |







## A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-1(X)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
  - 4.1. Planning Coordinators
  - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - 4.2.1 Transmission Owners
    - 4.2.2 Distribution Providers
  - 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

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

Deleted: (Proposed)

## B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [VRF: Medium][Time Horizon: Long-term Planning]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [VRF: Medium][Time Horizon: Long-term Planning]
  - 2.1. Those islands selected by applying the criteria in Requirement R1, and

Deleted: <#>The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals. ¶  
Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1(X), but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1(X).¶

- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme, and
  - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
- 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
    - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
    - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
    - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the

Deleted: Special Protection System

- Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
  - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
  - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
  - 11.1.** The performance of the UFLS equipment,
  - 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance

with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

**R14.** Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

**14.1.** UFLS program, including a schedule for implementation

**14.2.** UFLS design assessment

**14.3.** Format and schedule of UFLS data submittal

### **C. Measures**

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a

UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity

#### **1.2. Data Retention**

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

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.



- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

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

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

Not applicable.

**2. Violation Severity Levels**

| R # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
| R1  | N/A       | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>   |
| R2  | N/A       | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p> |

| R #       | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|-----------|--|--|---|--|
| <b>R3</b> | N/A  | <p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p> |
| <b>R4</b> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                         | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                      | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>   |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     |   |   |   | The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2                                 |
| R5  | N/A   | N/A   | N/A   | The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5. |
| R6  | N/A   | N/A   | N/A   | The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.  |
| R7  | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.<br>OR   |

| R #        | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL   |
|------------|---|--|---|--|
|            |   |  |   | The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.   |
| <b>R8</b>  | The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.                | The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br>The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. |
| <b>R9</b>  | The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. | The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   | The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.                  | The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   |
| <b>R10</b> | The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching  | The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching  | The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching   | The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,   |

| R #        | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|------------|--|---|---|--|
|            | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission   | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  | Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  |
| <b>R11</b> | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation. | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation. | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.<br><br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.<br><br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.<br><br>OR |

| R #        | Lower VSL | Moderate VSL   | High VSL   | Severe VSL   |
|------------|-----------|--|--|--|
|            |           |  | specified in Requirement R11, Parts 11.1 or 11.2.  | The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.  |
| <b>R12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.<br><br>OR<br>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies. |
| <b>R13</b> | N/A       | N/A  | N/A  | The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency  |

| R #        | Lower VSL | Moderate VSL | High VSL | Severe VSL   |
|------------|-----------|--------------|----------|--|
|            |           |              |          | excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13   |
| <b>R14</b> | N/A       | N/A          | N/A      | The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3. |



## E. Regional Variances

### E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

- E.A.3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).  
*[VRF: High][Time Horizon: Long-term Planning]*
- E.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
- EA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES
  - EA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES
  - EA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.
- E.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*
- E.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1A, and

- E.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 2A, and
  - E.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- M.E.A.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.
- M.E.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

| E # | Lower VSL | Moderate VSL   | High VSL  | Severe VSL   |
|-----|-----------|--|---|--|
| EA3 | N/A       | <p>The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions</p>   | <p>The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions</p>   | <p>The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program.</p>  |
| EA4 | N/A       | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3.</p> <p>OR</p> <p>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3</p> |

**E.B. Regional Variance for the Western Electricity Coordinating Council**

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

**E.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.1.** Those islands selected by applying the criteria in Requirement E.B.1, and

**E.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme.

Deleted: Special Protection System

**EB.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

**E.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**E.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

**E.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**E.B.11.1.** The performance of the UFLS equipment,

**E.B.11.2** The effectiveness of the UFLS program

**E.B.12.** Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

- M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.
- M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.
- M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.
- M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.
- M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.
- M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

| E #   | Lower VSL | Moderate VSL   | High VSL  | Severe VSL   |
|-------|-----------|--|---|--|
| E.B.1 | N/A       | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p> |
| E.B.2 | N/A       | N/A  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>   |

| E #          | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|--------------|--|---|---|---|
|              |  |   |   | The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.  |
| <b>E.B.3</b> | N/A  | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area. |
| <b>E.B.4</b> | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island                      | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island                      | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island  |



| E #                  | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|----------------------|---|--|--|--|
|                      | <p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>  | <p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p> |
| <p><b>E.B.11</b></p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>   |

| E #    | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|--------|-----------|---|---|--|
|        |           |   | <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p> | <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> |
| E.B.12 | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design   | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design  |

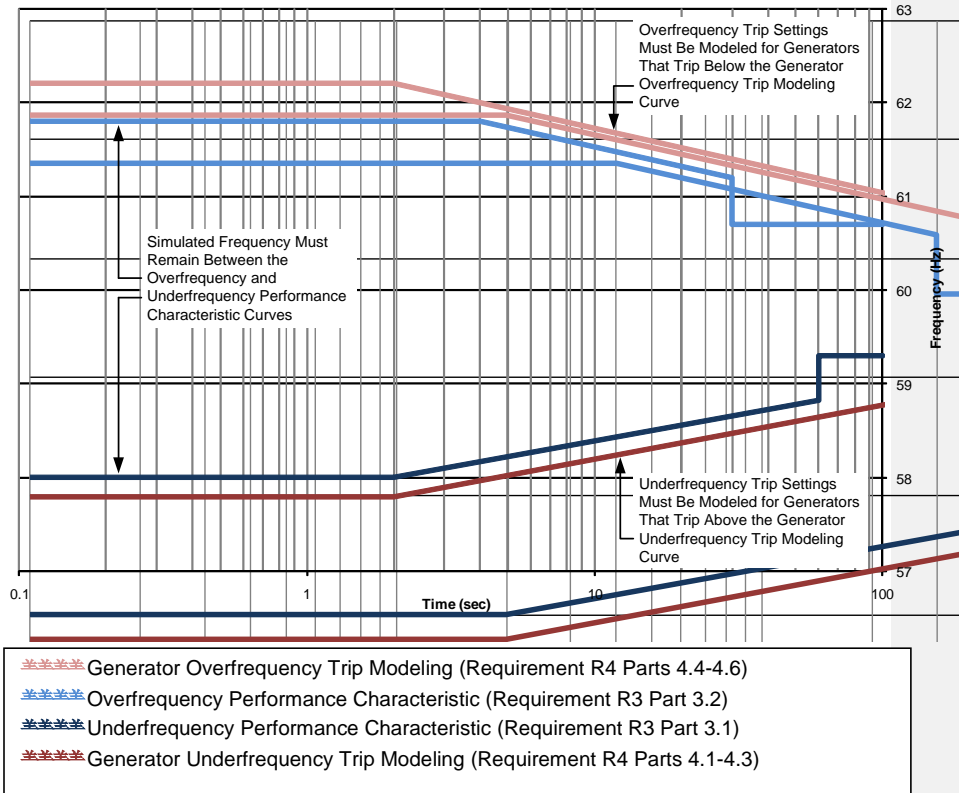
| E # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
|     |           | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p> |

**Associated Documents**

**Version History**

| Version              | Date                | Action   | Change Tracking  |
|----------------------|---------------------|--|--|
| 1                    | May 25, 2010        | Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.   |  |
| 1                    | November 4, 2010    | Adopted by the Board of Trustees   |  |
| 1                    | May 7, 2012         | FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)   |  |
| 1                    | November 9, 2012    | FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8. |  |
| <a href="#">1(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>  | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

**PRC-006-1(X) – Attachment 1**  
**Underfrequency Load Shedding Program**  
**Design Performance and Modeling Curves for**  
**Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6**

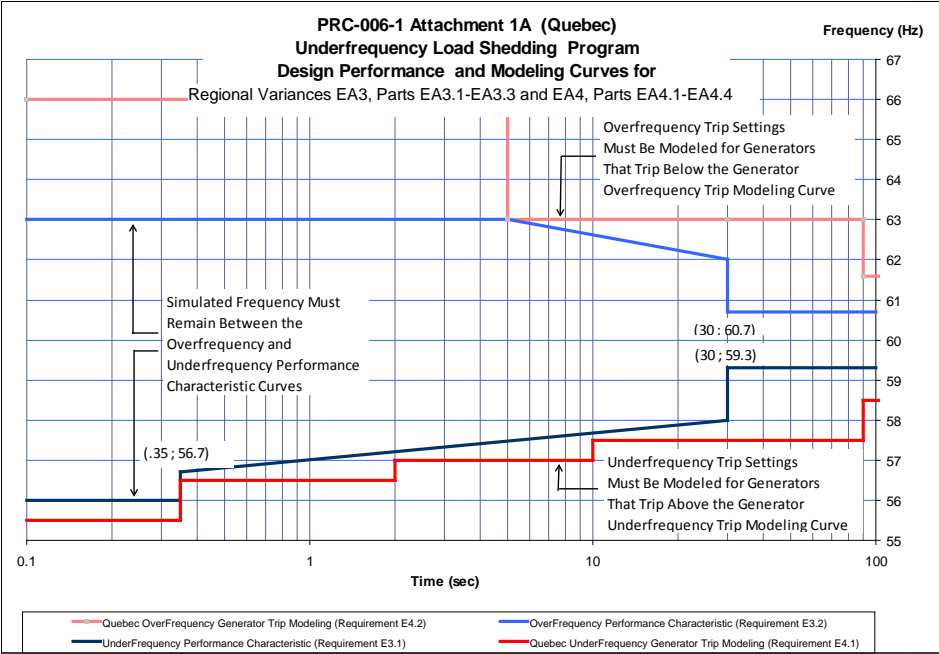


**Curve Definitions**

| Generator Overfrequency Trip Modeling |  | Overfrequency Performance Characteristic |  |                       |
|---------------------------------------|--|--|--|-----------------------|
| $t \leq 2 \text{ s}$                  | $t > 2 \text{ s}$                      | $t \leq 4 \text{ s}$                     | $4 \text{ s} < t \leq 30 \text{ s}$    | $t > 30 \text{ s}$    |
| $f = 62.2 \text{ Hz}$                 | $f = -0.686\log(t) + 62.41 \text{ Hz}$ | $f = 61.8 \text{ Hz}$                    | $f = -0.686\log(t) + 62.21 \text{ Hz}$ | $f = 60.7 \text{ Hz}$ |

| Generator Underfrequency Trip Modeling |                                       | Underfrequency Performance Characteristic |                                       |                       |
|--|---------------------------------------|---|---------------------------------------|-----------------------|
| $t \leq 2 \text{ s}$                   | $t > 2 \text{ s}$                     | $t \leq 2 \text{ s}$                      | $2 \text{ s} < t \leq 60 \text{ s}$   | $t > 60 \text{ s}$    |
| $f = 57.8 \text{ Hz}$                  | $f = 0.575\log(t) + 57.63 \text{ Hz}$ | $f = 58.0 \text{ Hz}$                     | $f = 0.575\log(t) + 57.83 \text{ Hz}$ | $f = 59.3 \text{ Hz}$ |





**A. Introduction**

1. **Title:** Remedial Action Scheme Review Procedure
2. **Number:** PRC-012-0(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:
  - R1.1. Description of the process for submitting a proposed RAS for Regional Reliability Organization review.
  - R1.2. Requirements to provide data that describes design, operation, and modeling of a RAS.
  - R1.3. Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4. Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5. Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6. Regional Reliability Organization definition of misoperation.
  - R1.7. Requirements for analysis and documentation of corrective action plans for all RAS misoperations.
  - R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9. Determination, as appropriate, of maintenance and testing requirements.



- R2.** The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**C. Measures**

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0(X)\_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-0(X)\_R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0(X)\_R1.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| <b>Version</b> | <b>Date</b>   | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|---------------|---------------------------------------|--|
| 0              | April 1, 2005 | Effective Date                        | New  |
| 0(X)           | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Standard PRC-012-0(X) — Remedial Action Scheme Review Procedure

A. Introduction

- 1. Title: Remedial Action Scheme Review Procedure
- 2. Number: PRC-012-0(X)
- 3. Purpose: To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:
  - 4.1. Regional Reliability Organization
- 5. Effective Date: This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: [Redacted]

Deleted: Special Protection System

Deleted: Special Protection Systems (SPS)

Deleted: April 1, 2005

B. Requirements

- R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:
  - R1.1. Description of the process for submitting a proposed RAS for Regional Reliability Organization review.
  - R1.2. Requirements to provide data that describes design, operation, and modeling of a RAS.
  - R1.3. Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4. Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5. Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6. Regional Reliability Organization definition of misoperation.
  - R1.7. Requirements for analysis and documentation of corrective action plans for all RAS misoperations.
  - R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9. Determination, as appropriate, of maintenance and testing requirements.

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Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: ¶ Effective Date: April 1, 2005

**Standard PRC-012-0(X) — Remedial Action Scheme Review Procedure**

**R2.** The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its **RAS** review procedure on request (within 30 calendar days).

Deleted: SPS

Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: ¶  
Effective Date: April 1, 2005

**Standard PRC-012-0(X) — Remedial Action Scheme Review Procedure**

**C. Measures**

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0(X) R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

Deleted: n SPS

Deleted: SPS

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-0(X) R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-0(X) R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-0(X) R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0(X) R1.

**E. Regional Differences**

- 1. None identified.

**Version History**

| Version     | Date          | Action                                       | Change Tracking   |
|-------------|---------------|--|---|
| 0           | April 1, 2005 | Effective Date                               | New   |
| <u>0(X)</u> | <u>TBD</u>    | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Deleted: ¶

Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: ¶  
Effective Date: April 1, 2005

## A. Introduction

1. **Title:** Remedial Action Scheme Database.
2. **Number:** PRC-013-0(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,
  - R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

## C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-0(X)\_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
  - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-0(X)\_R1.

**2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-0(X)\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0(X)\_R1.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Dave                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|         |               |                                       |  |
|         |               |                                       |  |

Standard PRC-013-0(X) — Remedial Action Scheme Database

A. Introduction

- 1. Title: Remedial Action Scheme Database.
- 2. Number: PRC-013-0(X)
- 3. Purpose: To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
- 4. Applicability:
  - 4.1. Regional Reliability Organization
- 5. Effective Date: This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: Special Protection System

Deleted: Special Protection Systems (SPSs)

B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,
  - R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

Deleted: April 1, 2005

Deleted: n SPS

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C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-0(X) R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

Deleted: n SPS

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D. Compliance

- 1. Compliance Monitoring Process
  - 1.1. Compliance Monitoring Responsibility
    - Compliance Monitor: NERC.
  - 1.2. Compliance Monitoring Period and Reset Timeframe

Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: Effective Date: April 1, 2005



Standard PRC-013-0(X) — Remedial Action Scheme Database

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-0(X)\_R1.

**2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-0(X)\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0(X)\_R1.

Deleted: 9

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Dave                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|         |               |                                       |  |
|         |               |                                       |  |

Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: Effective Date: April 1, 2005

**A. Introduction**

- 1. Title:** Remedial Action Scheme Assessment
- 2. Number:** PRC-014-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1. Regional Reliability Organization**
- 5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3.** The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:
  - R3.1.** Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems.
  - R3.5.** Provide corrective action plans for non-compliant RAS.

**C. Measures**

- M1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

- M3.** The Regional Reliability Organization's documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-0(X)\_R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-0(X)\_R3.

**2.2. Level 2:** The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-0(X)\_3.

**2.3. Level 3:** The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-0(X)\_R3.

**2.4. Level 4:** The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-0(X)\_R3 or was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|         |               |                                       |  |
|         |               |                                       |  |

Standard PRC-014-0(X) — Remedial Action Scheme Assessment

A. Introduction

- 1. **Title:** Remedial Action Scheme Assessment
- 2. **Number:** PRC-014-0(X)
- 3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. **Applicability:**
  - 4.1. Regional Reliability Organization
- 5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: Special Protection System

Deleted: Special Protection Systems (SPS)

Deleted: April 1, 2005

B. Requirements

- R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:
  - R3.1. Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3. Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4. Discussion of any coordination problems found between a RAS and other protection and control systems.
  - R3.5. Provide corrective action plans for non-compliant RAS.

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C. Measures

- M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

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Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: Effective Date: April 1, 2005

**Standard PRC-014-0(X) — Remedial Action Scheme Assessment**

**M3.** The Regional Reliability Organization's documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-0(X)\_R3.

Deleted: SPS

Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: Effective Date: April 1, 2005

Standard PRC-014-0(X) — Remedial Action Scheme Assessment

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-0(X)\_R3.

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2.2. Level 2: The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-0(X)\_3.

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2.3. Level 3: The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-0(X)\_R3.

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2.4. Level 4: The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-0(X)\_R3 or was not provided.

Deleted: SPS

E. Regional Differences

1. None identified.

Version History

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|         |               |                                       |  |
|         |               |                                       |  |

Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: Effective Date: April 1, 2005

**A. Introduction**

- 1. Title:** Remedial Action Scheme Data and Documentation
- 2. Number:** PRC-015-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Transmission Owner that owns a RAS
  - 4.2.** Generator Owner that owns a RAS
  - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-0(X)\_R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

**C. Measures**

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-0(X)\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional



Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

**2.2. Level 2:** RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-0(X)\_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard PRC-015-0(X) — Remedial Action Scheme Data and Documentation**

**A. Introduction**

- 1. **Title:** Remedial Action Scheme Data and Documentation
- 2. **Number:** PRC-015-0(X)
- 3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS
  - 4.2. Generator Owner that owns a RAS
  - 4.3. Distribution Provider that owns a RAS
- 5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: [Redacted]

Deleted: Special Protection System

Deleted: Special Protection Systems (SPS)

Deleted: n SPS

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Deleted: April 1, 2005

**B. Requirements**

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-0(X)\_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

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**C. Measures**

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-0(X)\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0(X)\_R1 prior to being placed in service.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional

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Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: Effective Date: April 1, 2005

**Standard PRC-015-0(X) — Remedial Action Scheme Data and Documentation**

Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

**2.2. Level 2:** RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-0(X)\_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)\_R1.

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**E. Regional Differences**

1. None identified.

**Version History**

| Version     | Date          | Action                                       | Change Tracking   |
|-------------|---------------|--|---|
| 0           | April 1, 2005 | Effective Date                               | New   |
| <u>0(X)</u> | <u>TBD</u>    | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

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Deleted: Adopted by NERC Board of Trustees: February 8, 2005

Deleted: Effective Date: April 1, 2005

### A. Introduction

1. **Title: Remedial Action Scheme Misoperations**
2. **Number:** PRC-016-0.1(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS.
  - 4.2. Generator Owner that owns a RAS.
  - 4.3. Distribution Provider that owns a RAS.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.

- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

**2.2. Level 2:** Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

**2.3. Level 3:** Documentation of RAS misoperations and corrective actions is incomplete.

**2.4. Level 4:** No documentation of RAS misoperations or corrective actions.

**E. Regional Differences**

None identified.

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|------------------|--|------------------------|
| 0              | April 1, 2005    | Effective Date   | New                    |
| 0              | February 8, 2005 | Adopted by NERC Board of Trustees                                    | New                    |
| 0              | July 3, 2007     | Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.” | Errata                 |

## Standard PRC-016-0.1(X) — Remedial Action Scheme Misoperations

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|        |                  |   |  |
|--------|------------------|---|--|
| 0.1    | October 29, 2008 | BOT adopted errata changes; updated version number to “0.1” | Errata   |
| 0.1    | May 13, 2009     | FERC Approved – Updated Effective Date                      | Revised  |
| 0.1(X) | TBD              | Adopted by the NERC Board of Trustees                       | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard PRC-016-0.1(X) — Remedial Action Scheme Misoperations**

**A. Introduction**

1. **Title:** Remedial Action Scheme Misoperations
2. **Number:** PRC-016-0.1(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS.
  - 4.2. Generator Owner that owns a RAS.
  - 4.3. Distribution Provider that owns a RAS.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: [Redacted]

Deleted: Special Protection System

Deleted: Special Protection Systems (SPS)

Deleted: n SPS

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**B. Requirements**

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

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**C. Measures**

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.

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**Standard PRC-016-0.1(X) — Remedial Action Scheme Misoperations**

**M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

Deleted: [redacted]

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**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

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**2.2. Level 2:** Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

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**2.3. Level 3:** Documentation of RAS misoperations and corrective actions is incomplete.

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**2.4. Level 4:** No documentation of RAS misoperations or corrective actions.

Deleted: SPS

**E. Regional Differences**

None identified.

Deleted: ¶

**Version History**

| Version | Date             | Action   | Change Tracking |
|---------|------------------|--|-----------------|
| 0       | April 1, 2005    | Effective Date   | New             |
| 0       | February 8, 2005 | Adopted by NERC Board of Trustees                                    | New             |
| 0       | July 3, 2007     | Change reference in Measure 1 from "PRC-016-0_R1" to "PRC-012-1_R1." | Errata          |



**Standard PRC-016-0.1(X) — Remedial Action Scheme Misoperations**

|                        |                     |   |  |
|------------------------|---------------------|---|--|
| 0.1                    | October 29, 2008    | BOT adopted errata changes; updated version number to “0.1” | Errata   |
| 0.1                    | May 13, 2009        | FERC Approved – Updated Effective Date                      | Revised  |
| <a href="#">0.1(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>       | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

**A. Introduction**

- 1. Title:** Remedial Action Scheme Maintenance and Testing
- 2. Number:** PRC-017-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Transmission Owner that owns a RAS
  - 4.2.** Generator Owner that owns a RAS
  - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1.** RAS identification shall include but is not limited to:
    - R1.1.1.** Relays.
    - R1.1.2.** Instrument transformers.
    - R1.1.3.** Communications systems, where appropriate.
    - R1.1.4.** Batteries.
  - R1.2.** Documentation of maintenance and testing intervals and their basis.
  - R1.3.** Summary of testing procedure.
  - R1.4.** Schedule for system testing.
  - R1.5.** Schedule for system maintenance.
  - R1.6.** Date last tested/maintained.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**C. Measures**

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0(X)\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the program and its implementation to the

**Standard PRC-017-0(X) — Remedial Action Scheme Maintenance and Testing**

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appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

**1.2. Compliance Monitoring Period and Reset Timeframe**

Compliance Monitor: Regional Reliability Organization.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 0(X)    | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard PRC-017-0(X) — Remedial Action Scheme Maintenance and Testing**

**A. Introduction**

1. **Title:** Remedial Action Scheme Maintenance and Testing
2. **Number:** PRC-017-0(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS
  - 4.2. Generator Owner that owns a RAS
  - 4.3. Distribution Provider that owns a RAS
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Deleted: Special Protection Systems (SPS)

Deleted: n SPS

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**B. Requirements**

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1. RAS identification shall include but is not limited to:
    - R1.1.1. Relays.
    - R1.1.2. Instrument transformers.
    - R1.1.3. Communications systems, where appropriate.
    - R1.1.4. Batteries.
  - R1.2. Documentation of maintenance and testing intervals and their basis.
  - R1.3. Summary of testing procedure.
  - R1.4. Schedule for system testing.
  - R1.5. Schedule for system maintenance.
  - R1.6. Date last tested/maintained.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

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**C. Measures**

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0(X)\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the program and its implementation to the

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Effective Date: April 1, 2005

**Standard PRC-017-0(X) — Remedial Action Scheme Maintenance and Testing**

appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

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Effective Date: April 1, 2005

**Standard PRC-017-0(X) — Remedial Action Scheme Maintenance and Testing**

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

**1.2. Compliance Monitoring Period and Reset Timeframe**

Compliance Monitor: Regional Reliability Organization.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

- 1. None identified.

**Version History**

| Version              | Date                | Action  | Change Tracking  |
|----------------------|---------------------|---|--|
| 0                    | April 1, 2005       | Effective Date  | New  |
| <a href="#">0(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a> | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

Deleted: Adopted by NERC Board of Trustees: February 8, 2005

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Effective Date: April 1, 2005

## A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Database
2. **Number:** PRC-020-1(X)
3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
4. **Applicability**
  - 4.1. Regional Reliability Organization with entities that own or operate a UVLS program.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
  - R1.1. Owner and operator of the UVLS program.
  - R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.3. Corresponding voltage set points and overall scheme clearing times.
  - R1.4. Time delay from initiation to trip signal.
  - R1.5. Breaker operating times.
  - R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

## C. Measures

- M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**



## Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

NERC

### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

### 1.3. Data Retention

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Did not update its UVLS database annually.

**2.2. Level 2:** UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Did not provide information from its UVLS program database.

## E. Regional Differences

None identified.

## Version History

| Version | Date     | Action   | Change Tracking  |
|---------|----------|--|--|
| 1       | 12/01/05 | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>4. Added or removed “periods” where appropriate.</li> <li>5. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/06   |
| 1(X)    | TBD      | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

### A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Database
2. **Number:** PRC-020-1(X)
3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
4. **Applicability**
  - 4.1. Regional Reliability Organization with entities that own or operate a UVLS program.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: May 1, 2006

### B. Requirements

- R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
  - R1.1. Owner and operator of the UVLS program.
  - R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.3. Corresponding voltage set points and overall scheme clearing times.
  - R1.4. Time delay from initiation to trip signal.
  - R1.5. Breaker operating times.
  - R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

Deleted: Special Protection System

### C. Measures

- M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

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**Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database**

NERC

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

**1.4. Additional Compliance Information**

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Did not update its UVLS database annually.

**2.2. Level 2:** UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Did not provide information from its UVLS program database.

**E. Regional Differences**

None identified.

**Version History**

| Version     | Date       | Action   | Change Tracking   |
|-------------|------------|--|---|
| 1           | 12/01/05   | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>4. Added or removed “periods” where appropriate.</li> <li>5. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/06  |
| <u>1(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u>   | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

Deleted: Adopted by Board of Trustees: February 7, 2006

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### A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Data
2. **Number:** PRC-021-1(X)
3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. **Applicability**
  - 4.1. Transmission Owner that owns a UVLS program.
  - 4.2. Distribution Provider that owns a UVLS program.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### B. Requirements

- R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
  - R1.1. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.2. Corresponding voltage set points and overall scheme clearing times.
  - R1.3. Time delay from initiation to trip signal.
  - R1.4. Breaker operating times.
  - R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

### C. Measures

- M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

## Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data

Regional Reliability Organization.

### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

### 1.3. Data Retention

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Did not update its UVLS data annually.

**2.2. Level 2:** UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

**2.3. Level 3:** UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

**2.4. Level 4:** Did not provide any UVLS data.

## E. Regional Differences

None identified.

## Version History

| Version | Date     | Action  | Change Tracking   |
|---------|----------|---|---|
| 1       | 12/01/05 | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>3. Added heading above table “Future Development Plan.”</li> <li>4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>5. Added or removed “periods” where appropriate.</li> <li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05  |
| 1(X)    | TBD      | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with |

**Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data**

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|  |  |  | Remedial Action Scheme and RAS |
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## Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data

### A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Data
2. **Number:** PRC-021-1(X)
3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. **Applicability**
  - 4.1. Transmission Owner that owns a UVLS program.
  - 4.2. Distribution Provider that owns a UVLS program.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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### B. Requirements

- R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
  - R1.1. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.2. Corresponding voltage set points and overall scheme clearing times.
  - R1.3. Time delay from initiation to trip signal.
  - R1.4. Breaker operating times.
  - R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and [Remedial Action Schemes](#).
- R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

Deleted: Special Protection System

### C. Measures

- M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Deleted: Adopted by Board of Trustees: February 7, 2006

Deleted: Effective Date: August 1, 2006

**Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data**

Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

**1.4. Additional Compliance Information**

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Did not update its UVLS data annually.

**2.2. Level 2:** UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

**2.3. Level 3:** UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

**2.4. Level 4:** Did not provide any UVLS data.

**E. Regional Differences**

None identified.

**Version History**

| Version              | Date                | Action  | Change Tracking   |
|----------------------|---------------------|---|---|
| 1                    | 12/01/05            | <ol style="list-style-type: none"> <li>Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>Added heading above table “Future Development Plan.”</li> <li>Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>Added or removed “periods” where appropriate.</li> <li>Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05  |
| <a href="#">1(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>   | <a href="#">Replaced references to Special Protection System and SPS with</a> |

Deleted: Adopted by Board of Trustees: February 7, 2006

Deleted: Effective Date: August 1, 2006



**Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data**

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|  |  |  | <a href="#">Remedial Action Scheme and RAS</a> |
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Deleted: Adopted by Board of Trustees: February 7, 2006  
Deleted: Effective Date: August 1, 2006

**A. Introduction**

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-2(X)

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability**

**4.1. Functional Entity**

**4.1.1** Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

**4.1.2** Generator Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

**4.1.3** Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

**4.1.4** Planning Coordinators

**4.2. Circuits**

**4.2.1 Circuits Subject to Requirements R1 – R5**

**4.2.1.1** Transmission lines operated at 200 kV and above.

**4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

**4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

**4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above.

**4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

**4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

**4.2.2 Circuits Subject to Requirement R6**

**4.2.2.1** Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

**5. Effective Dates:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the

## **Standard PRC-023-2(X) — Transmission Relay Loadability**

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standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

**Criteria:**

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(X) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.



2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>   |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>   |

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| Requirement | Lower | Moderate   | High   | Severe   |
|-------------|-------|--|--|--|
|             |       |  |  | The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.<br><br>OR<br><br>The Planning Coordinator used the criteria established within   |

**Standard PRC-023-2(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe   |
|-------------|-------|---|--|--|
|             |       | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p> |

**Standard PRC-023-2(X) — Transmission Relay Loadability**

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| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
|             |       |          |      | <p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking  |
|---------|--|---|--|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New  |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata   |
| 1       | March 18, 2010                               | Approved by FERC  |  |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision   |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)   |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |  |
| 2(X)    | TBD  | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023 — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Generator protection relays that are susceptible to load.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

**PRC-023 — Attachment B**

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-2(X) — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.



## Standard PRC-023-2(X) — Transmission Relay Loadability

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### A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-2(X)
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability**
  - 4.1. **Functional Entity**
    - 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinators
  - 4.2. **Circuits**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5**
      - 4.2.1.1 Transmission lines operated at 200 kV and above.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.
    - 4.2.2 **Circuits Subject to Requirement R6**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV
      - 4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES
5. **Effective Dates:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the

**Standard PRC-023-2(X) — Transmission Relay Loadability**

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standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**Commented [KS1]:** Deleted: Effective Date table.

**Deleted:** The effective dates of the requirements in the PRC-023-2(X) standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:¶

## Standard PRC-023-2(X) — Transmission Relay Loadability

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### B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

#### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

## Standard PRC-023-2(X) — Transmission Relay Loadability

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8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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<sup>2</sup> As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

## Standard PRC-023-2(X) — Transmission Relay Loadability

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(X) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
  - 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

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- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

##### 1.2. Data Retention

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

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The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

None.

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**2. Violation Severity Levels:**

| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>   |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>   |



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| Requirement | Lower | Moderate   | High   | Severe   |
|-------------|-------|--|--|--|
|             |       |  |  | The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.<br><br>OR<br>The Planning Coordinator used the criteria established within   |

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| Requirement | Lower | Moderate  | High   | Severe   |
|-------------|-------|---|--|--|
|             |       | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p> |

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| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
|             |       |          |      | <p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

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**E. Regional Differences**

None

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: [http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version     | Date   | Action  | Change Tracking   |
|-------------|--|---|---|
| 1           | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1           | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1           | March 18, 2010                               | Approved by FERC  |   |
| 1           | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2           | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2           | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| <u>2(X)</u> | <u>TBD</u>                                   | <u>Adopted by the NERC Board of Trustees</u>  | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## Standard PRC-023-2(X) — Transmission Relay Loadability

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### PRC-023 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Generator protection relays that are susceptible to load.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

Deleted: Special Protection System

**PRC-023 — Attachment B**

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
  - a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

## **A. Introduction**

- 1. Title:**           **Transmission Relay Loadability**
- 2. Number:**       PRC-023-3(X)
- 3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
- 4. Applicability:**
  - 4.1. Functional Entity:**
    - 4.1.1** Transmission Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2** Generator Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3** Distribution Provider with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4** Planning Coordinator
  - 4.2. Circuits:**
    - 4.2.1 Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1** Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 Circuits Subject to Requirement R6:**
      - 4.2.2.1** Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.



**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

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

## **B. Requirements**

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

### **Criteria:**

- 1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
- 2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
- 3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
- 4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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- b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-3(X) per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3(X), Attachment B applies.
  - 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High  | Severe   |
|-------------|-------|---|---|--|
|             |       |   |   | OR<br>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.  |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |



**Standard PRC-023-3(X) — Transmission Relay Loadability**

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| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
|             |       | <p>the list was established or updated. (part 6.2)</p> |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None.

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

[http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

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| Version | Date | Action                                | Change Tracking  |
|---------|------|---------------------------------------|--|
| 3(X)    | TBD  | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023-3(X) — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

**PRC-023-3(X) — Attachment B**

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-3(X) — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

## Standard PRC-023-3(X) — Transmission Relay Loadability

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### A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-3(X)
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
  - 4.1. **Functional Entity:**
    - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinator
  - 4.2. **Circuits:**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 **Circuits Subject to Requirement R6:**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

## Standard PRC-023-3(X) — Transmission Relay Loadability

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

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

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### B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

#### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.



## Standard PRC-023-3(X) — Transmission Relay Loadability

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5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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<sup>2</sup> As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

## Standard PRC-023-3(X) — Transmission Relay Loadability

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- b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-3(X) per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3(X), Attachment B applies.
  - 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

## Standard PRC-023-3(X) — Transmission Relay Loadability

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set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence to show that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

##### 1.2. Data Retention

## Standard PRC-023-3(X) — Transmission Relay Loadability

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

### 1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### 1.4. Additional Compliance Information

None.

**Standard PRC-023-3(X) — Transmission Relay Loadability**

**2. Violation Severity Levels:**

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High  | Severe   |
|-------------|-------|---|---|--|
|             |       |   |   | OR<br>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.  |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |

**Standard PRC-023-3(X) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High | Severe  |
|-------------|-------|---|------|---|
|             |       | the list was established or updated. (part 6.2) |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |



## Standard PRC-023-3(X) — Transmission Relay Loadability

### E. Regional Differences

None.

### F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: [http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

### Version History

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |

Standard PRC-023-3(X) — Transmission Relay Loadability

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| Version     | Date       | Action                                       | Change Tracking   |
|-------------|------------|--|---|
| <u>3(X)</u> | <u>TBD</u> | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## Standard PRC-023-3(X) — Transmission Relay Loadability

### PRC-023-3(X) — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for [Remedial Action Schemes](#) applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

Deleted: Special Protection System

## Standard PRC-023-3(X) — Transmission Relay Loadability

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### PRC-023-3(X) — Attachment B

#### Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

#### Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
  - a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

### Standard PRC-023-3(X) — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

**A. Introduction**

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-1(X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
  - 4.1. Generator Owner

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

**B. Requirements**

- R1.** Each Generator Owner that has generator frequency protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
  - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
  - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection<sup>2</sup>) caused by an event on the

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<sup>1</sup> Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

<sup>2</sup> For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

**R3.** Each Generator Owner shall document each known regulatory or equipment limitation<sup>3</sup> that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

**3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

**R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or

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<sup>3</sup> Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

Transmission Planner that the reporting of relay setting changes is not required.  
*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

### **C. Measures**

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.
- M4.** Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

##### **1.1. Data Retention**

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.



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

**1.2. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.3. Additional Compliance Information**

None

2. Violation Severity Levels

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
| <b>R1</b> | N/A   | N/A   | N/A   | The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.   |
| <b>R2</b> | N/A   | N/A   | N/A   | The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3. |
| <b>R3</b> | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.  |

## Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
|           | limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.   | OR<br>The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.  |
| <b>R4</b> | The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request. | The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner failed to provide trip settings within 150 calendar days of a written request. |

### E. Regional Variances

None

### F. Associated Documents

None

### Version History

| Version | Date        | Action                                | Change Tracking |
|---------|-------------|---------------------------------------|-----------------|
| 1       | May 9, 2013 | Adopted by the NERC Board of Trustees |                 |

## Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

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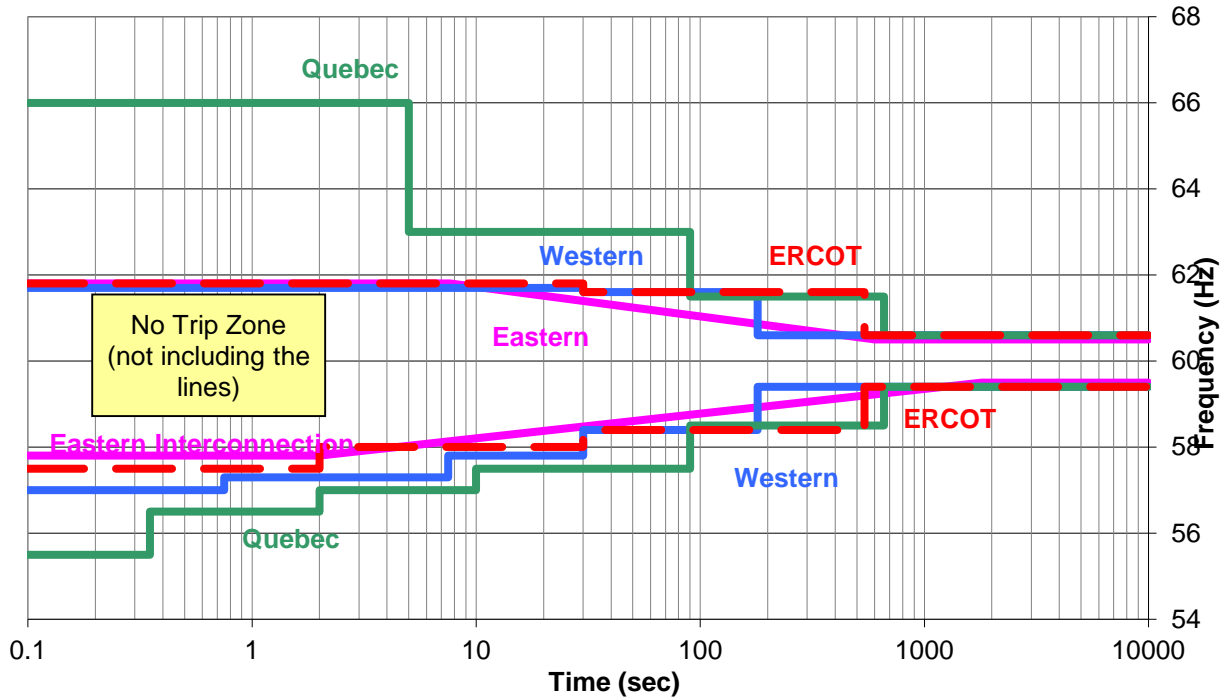
|      |                |   |  |
|------|----------------|---|--|
| 1    | March 20, 2014 | FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.) |  |
| 1(X) | TBD            | Adopted by the NERC Board of Trustees                                       | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

| High Frequency Duration |                           | Low Frequency Duration |                           |
|-------------------------|---------------------------|------------------------|---------------------------|
| Frequency (Hz)          | Time (Sec)                | Frequency (Hz)         | Time (sec)                |
| ≥61.8                   | Instantaneous trip        | ≤57.8                  | Instantaneous trip        |
| ≥60.5                   | $10^{(90.935-1.45713*f)}$ | ≤59.5                  | $10^{(1.7373*f-100.116)}$ |
| <60.5                   | Continuous operation      | > 59.5                 | Continuous operation      |

**Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings**

**Western Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.7                   | Instantaneous trip   | ≤57.0                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤57.3                  | 0.75                 |
| ≥60.6                   | 180                  | ≤57.8                  | 7.5                  |
| <60.6                   | Continuous operation | ≤58.4                  | 30                   |
|                         |                      | ≤59.4                  | 180                  |
|                         |                      | >59.4                  | Continuous operation |

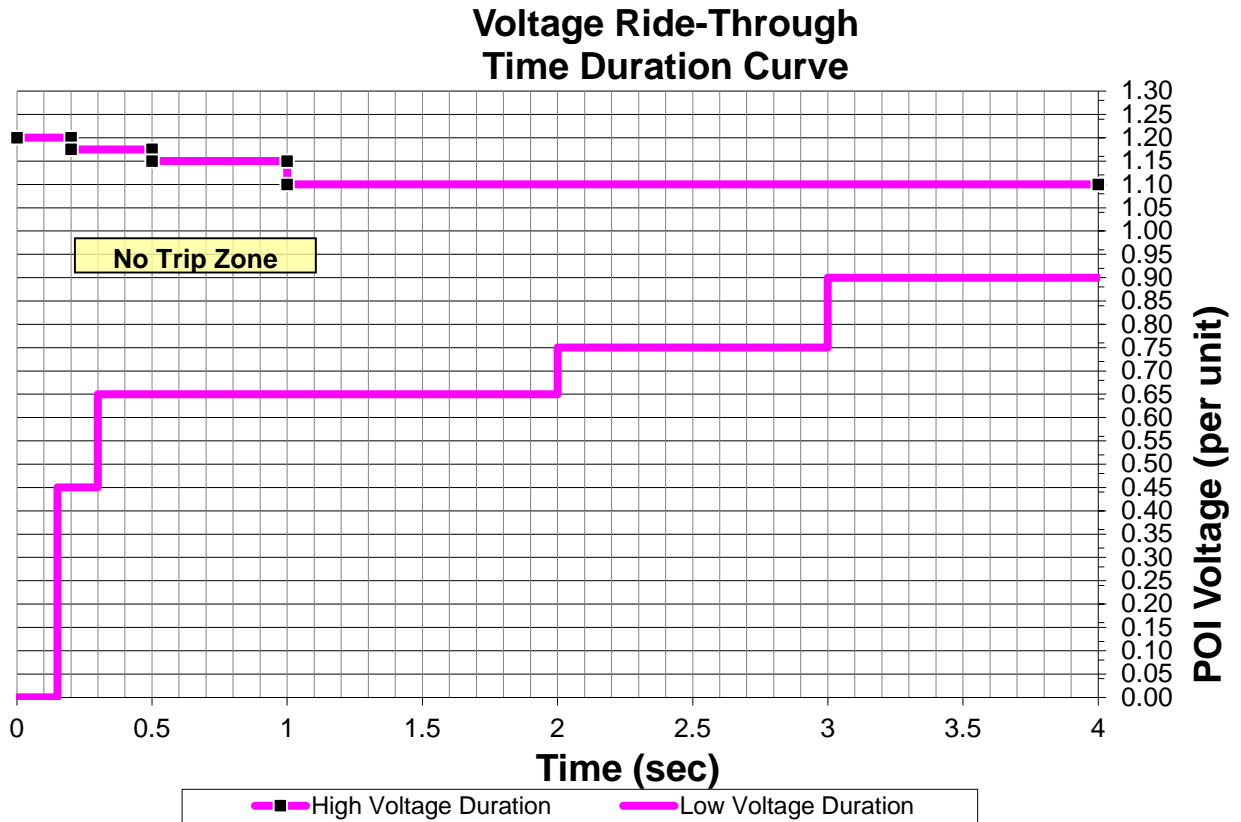
**Quebec Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (Sec)           |
| >66.0                   | Instantaneous trip   | <55.5                  | Instantaneous trip   |
| ≥63.0                   | 5                    | ≤56.5                  | 0.35                 |
| ≥61.5                   | 90                   | ≤57.0                  | 2                    |
| ≥60.6                   | 660                  | ≤57.5                  | 10                   |
| <60.6                   | Continuous operation | ≤58.5                  | 90                   |
|                         |                      | ≤59.4                  | 660                  |
|                         |                      | >59.4                  | Continuous operation |

**ERCOT Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.8                   | Instantaneous trip   | ≤57.5                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤58.0                  | 2                    |
| ≥60.6                   | 540                  | ≤58.4                  | 30                   |
| <60.6                   | Continuous operation | ≤59.4                  | 540                  |
|                         |                      | >59.4                  | Continuous operation |

PRC-024— Attachment 2



**Ride Through Duration:**

| High Voltage Ride Through Duration |                    | Low Voltage Ride Through Duration |            |
|------------------------------------|--------------------|-----------------------------------|------------|
| Voltage (pu)                       | Time (sec)         | Voltage (pu)                      | Time (sec) |
| ≥1.200                             | Instantaneous trip | <0.45                             | 0.15       |
| ≥1.175                             | 0.20               | <0.65                             | 0.30       |
| ≥1.15                              | 0.50               | <0.75                             | 2.00       |
| ≥1.10                              | 1.00               | <0.90                             | 3.00       |

## **Voltage Ride-Through Curve Clarifications**

### **Curve Details:**

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

### **Evaluating Protective Relay Settings:**

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
  - a. All of the units connected to the same transformer are online and operating.
  - b. All of the units are at full nameplate real-power output.
  - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
  - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.



## Standard PRC-024-1 (X) — Generator Frequency and Voltage Protective Relay Settings

### A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-1 (X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
  - 4.1. Generator Owner

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

### B. Requirements

- R1. Each Generator Owner that has generator frequency protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
  - Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
  - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
  - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2. Each Generator Owner that has generator voltage protective relaying<sup>1</sup> activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection<sup>2</sup>) caused by an event on the

<sup>1</sup> Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

<sup>2</sup> For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

**Deleted: 5.1.** In those jurisdictions where regulatory approval is required:¶

**5.1.1** By the first day of the first calendar quarter, two calendar years following¶ applicable regulatory approval, or as otherwise made effective pursuant to¶ the laws applicable to such ERO governmental authorities, each Generator¶ Owner shall have verified at least 40 percent of its Facilities are fully¶ compliant with Requirements R1, R2, R3, and R4.¶

**5.1.2** By the first day of the first calendar quarter, three calendar years following¶ applicable regulatory approval, or as otherwise made effective pursuant to¶ the laws applicable to such ERO governmental authorities, each Generator¶ Owner shall have verified at least 60 percent of its Facilities are fully¶ compliant with Requirements R1, R2, R3, and R4.¶

**5.1.3** By the first day of the first calendar quarter, four calendar years following¶ applicable regulatory approval, or as otherwise made effective pursuant to¶ the laws applicable to such ERO governmental authorities, each Generator¶ Owner shall have verified at least 80 percent of its Facilities are fully¶ compliant with Requirements R1, R2, R3, and R4. **5.1.4** By the first day of the first calendar quarter, five calendar years following¶ applicable regulatory approval, or as otherwise made effective pursuant to¶ the laws applicable to such ERO governmental authorities, each Generator¶ Owner shall have verified 100 percent of its Facilities are fully compliant¶ with Requirements R1, R2, R3, and R4.¶

**5.2.** In those jurisdictions where regulatory approval is not required:¶

**5.2.1** By the first day of the first calendar quarter, two calendar years following¶

## Standard PRC-024-1 (X) — Generator Frequency and Voltage Protective Relay Settings

transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Remedial Action Scheme (RAS).
  - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
  - Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
  - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R3.** Each Generator Owner shall document each known regulatory or equipment limitation<sup>3</sup> that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:
- Identification of a regulatory or equipment limitation.
  - Repair of the equipment causing the limitation that removes the limitation.
  - Replacement of the equipment causing the limitation with equipment that removes the limitation.
  - Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or

**Deleted:** Special Protection System (SPS)  
or

<sup>3</sup> Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

## **Standard PRC-024-1 (X) — Generator Frequency and Voltage Protective Relay Settings**

Transmission Planner that the reporting of relay setting changes is not required.  
*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

### **C. Measures**

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.
- M4.** Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

##### **1.1. Data Retention**

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

**Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings**

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

**1.2. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.3. Additional Compliance Information**

None

Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

2. Violation Severity Levels

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
| <b>R1</b> | N/A   | N/A   | N/A   | The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.   |
| <b>R2</b> | N/A   | N/A   | N/A   | The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3. |
| <b>R3</b> | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented | The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.  |

Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----------|---|---|---|---|
|           | limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.  | limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.   | OR<br>The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.  |
| <b>R4</b> | The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request. | The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request. | The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings.<br><br>OR<br>The Generator Owner failed to provide trip settings within 150 calendar days of a written request. |

**E. Regional Variances**

None

**F. Associated Documents**

None

**Version History**

| Version | Date        | Action                                | Change Tracking |
|---------|-------------|---------------------------------------|-----------------|
| 1       | May 9, 2013 | Adopted by the NERC Board of Trustees |                 |

**Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings**

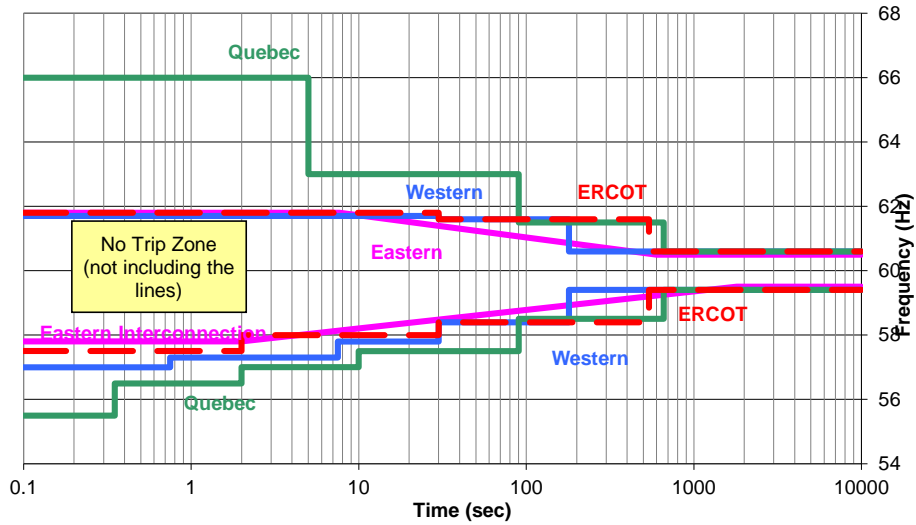
|                      |                     |   |  |
|----------------------|---------------------|---|--|
| 1                    | March 20, 2014      | FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.) |  |
| <a href="#">1(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>                       | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

**G. References**

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

| High Frequency Duration |                           | Low Frequency Duration |                           |
|-------------------------|---------------------------|------------------------|---------------------------|
| Frequency (Hz)          | Time (Sec)                | Frequency (Hz)         | Time (sec)                |
| ≥61.8                   | Instantaneous trip        | ≤57.8                  | Instantaneous trip        |
| ≥60.5                   | $10^{(90.935-1.45713*f)}$ | ≤59.5                  | $10^{(1.7373*f-100.116)}$ |
| <60.5                   | Continuous operation      | > 59.5                 | Continuous operation      |



Standard PRC-024-1 (X) — Generator Frequency and Voltage Protective Relay Settings

**Western Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.7                   | Instantaneous trip   | ≤57.0                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤57.3                  | 0.75                 |
| ≥60.6                   | 180                  | ≤57.8                  | 7.5                  |
| <60.6                   | Continuous operation | ≤58.4                  | 30                   |
|                         |                      | ≤59.4                  | 180                  |
|                         |                      | >59.4                  | Continuous operation |

**Quebec Interconnection**

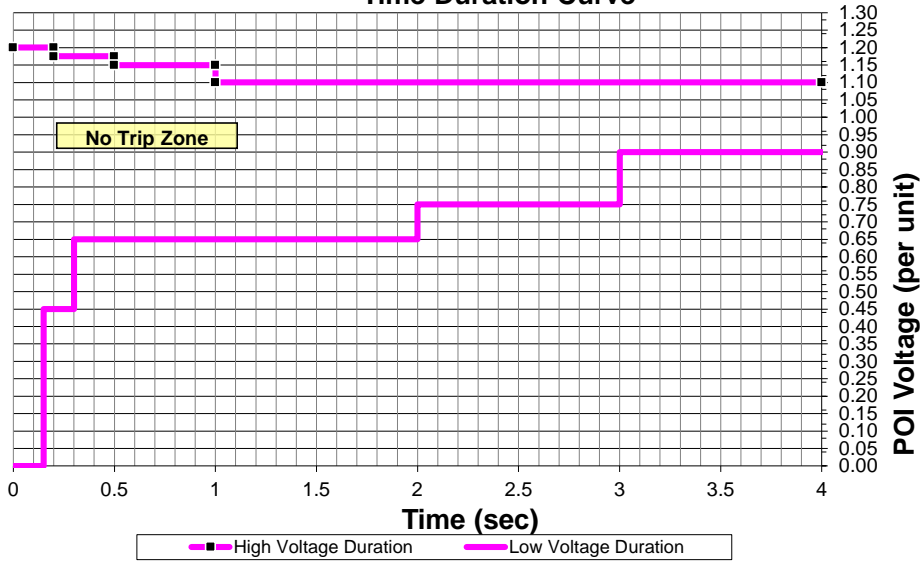
| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (Sec)           |
| >66.0                   | Instantaneous trip   | <55.5                  | Instantaneous trip   |
| ≥63.0                   | 5                    | ≤56.5                  | 0.35                 |
| ≥61.5                   | 90                   | ≤57.0                  | 2                    |
| ≥60.6                   | 660                  | ≤57.5                  | 10                   |
| <60.6                   | Continuous operation | ≤58.5                  | 90                   |
|                         |                      | ≤59.4                  | 660                  |
|                         |                      | >59.4                  | Continuous operation |

**ERCOT Interconnection**

| High Frequency Duration |                      | Low Frequency Duration |                      |
|-------------------------|----------------------|------------------------|----------------------|
| Frequency (Hz)          | Time (Sec)           | Frequency (Hz)         | Time (sec)           |
| ≥61.8                   | Instantaneous trip   | ≤57.5                  | Instantaneous trip   |
| ≥61.6                   | 30                   | ≤58.0                  | 2                    |
| ≥60.6                   | 540                  | ≤58.4                  | 30                   |
| <60.6                   | Continuous operation | ≤59.4                  | 540                  |
|                         |                      | >59.4                  | Continuous operation |

PRC-024— Attachment 2

Voltage Ride-Through Time Duration Curve



Ride Through Duration:

| High Voltage Ride Through Duration |                    | Low Voltage Ride Through Duration |            |
|------------------------------------|--------------------|-----------------------------------|------------|
| Voltage (pu)                       | Time (sec)         | Voltage (pu)                      | Time (sec) |
| $\geq 1.200$                       | Instantaneous trip | $< 0.45$                          | 0.15       |
| $\geq 1.175$                       | 0.20               | $< 0.65$                          | 0.30       |
| $\geq 1.15$                        | 0.50               | $< 0.75$                          | 2.00       |
| $\geq 1.10$                        | 1.00               | $< 0.90$                          | 3.00       |

### Voltage Ride-Through Curve Clarifications

#### Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

#### Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
  - a. All of the units connected to the same transformer are online and operating.
  - b. All of the units are at full nameplate real-power output.
  - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
  - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAR compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

## A. Introduction

1. **Title:** Generator Relay Loadability

2. **Number:** PRC-025-1(X)

**Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

### 3.1. Functional Entities:

**3.1.1** Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

**3.1.2** Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

**3.1.3** Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

**3.2. Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

**3.2.1** Generating unit(s).

**3.2.2** Generator step-up (i.e., GSU) transformer(s).

**3.2.3** Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.<sup>1</sup>

**3.2.4** Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**3.2.5** Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

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<sup>1</sup> These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1(X) Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.<sup>2</sup>

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

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

## B. Requirements and Measures

- R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.  
*[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
- M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1(X) – Attachment 1: Relay Settings.

## C. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Enforcement Authority**

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

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<sup>2</sup> Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

**1.2. Evidence Retention**

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

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None

**Table of Compliance Elements**

| R # | Time Horizon       | VRF  | Violation Severity Levels |              |          |   |
|-----|--------------------|------|---------------------------|--------------|----------|---|
|     |                    |      | Lower VSL                 | Moderate VSL | High VSL | Severe VSL  |
| R1  | Long-Term Planning | High | N/A                       | N/A          | N/A      | The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on an applied load-responsive protective relay. |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

## **PRC-025-1(X) – Attachment 1: Relay Settings**

### **Introduction**

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

### **Generators**

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

### **Transformers**

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.



## Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

## Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.<sup>3</sup>
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

## Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

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<sup>3</sup> IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

| Table 1. Relay Loadability Evaluation Criteria   |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system | 1a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b>                             |  |           |   |   |  |

<sup>4</sup> Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

| Table 1. Relay Loadability Evaluation Criteria   |   |   |   |  |  |
|--|---|---|---|--|--|
| Application  | Relay Type  | Option  | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 2a  | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b>   |   |  |  |
|  |   | 2b  | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b>   |   |  |  |
|  | 2c  | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and<br>(2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation |  |  |
| <b>The same application continues with a different relay type below</b>  |   |   |   |  |  |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 3   | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer   | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |  |
| <b>A different application starts on the next page</b>   |   |   |   |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |   |        |   |  |
|--|---|--------|---|--|
| Application  | Relay Type  | Option | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |
| Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system                                  | 4      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|  | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 5      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 6      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |
| A different application starts on the next page  |   |        |   |  |

| Table 1. Relay Loadability Evaluation Criteria                                     |  |           |   |  |  |
|--|--|-----------|---|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 14 | 7a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br><br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b> |  |           |   |  |  |

| Table 1. Relay Loadability Evaluation Criteria                                     |   |           |   |   |  |
|--|---|-----------|---|---|--|
| Application  | Relay Type  | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 15 | 8a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b> |   |           |   |   |  |

| Table 1. Relay Loadability Evaluation Criteria                       |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 16 | 9a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>A different application starts on the next page</b>               |  |           |   |   |  |



| Table 1. Relay Loadability Evaluation Criteria  |  |        |  |  |
|---|--|--------|--|--|
| Application   | Relay Type   | Option | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 17 | 10     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|   | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 18                                      | 11     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | <b>The same application continues on the next page with a different relay type</b>   |        |  |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |   |  |  |
|---|--|-----------|---|--|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer                | 12        | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |  |
|   | If the relay is installed on the high-side of the GSU transformer use Option 19  |           |   |  |  |
| <b>A different application starts below</b>   |  |           |   |  |  |
| Unit auxiliary transformer(s) (UAT)   | Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip. | 13a       | 1.0 per unit of the winding nominal voltage of the unit auxiliary transformer   | The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating  |  |
|   |  | <b>OR</b> |   |  |  |
|   |  | 13b       | Unit auxiliary transformer bus voltage corresponding to the measured current  | The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner  |  |
| <b>A different application starts on the next page</b>  |  |           |   |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |  |           |  |  |
|--|--|-----------|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators | Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer | 14a       | 0.85 per unit of the line nominal voltage  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |
|  |  | <b>OR</b> |  |  |
|  | If the relay is installed on the generator-side of the GSU transformer use Option 7  | 14b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |
| <b>The same application continues on the next page with a different relay type</b>   |  |           |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |   |           |  |   |  |
|--|---|-----------|--|---|--|
| Application  | Relay Type  | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria   |  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators | Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer<br><br>If the relay is installed on the generator-side of the GSU transformer use Option 8 | 15a       | 0.85 per unit of the line nominal voltage  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |  |   |  |
|  |   | 15b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br><br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| <b>The same application continues on the next page with a different relay type</b>   |   |           |  |   |  |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |  |   |  |
|---|--|-----------|--|---|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria   |  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators | Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer | 16a       | 0.85 per unit of the line nominal voltage  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|   |  | <b>OR</b> |  |   |  |
|   |  | 16b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |  |
| A different application starts on the next page   |  |           |  |   |  |

| Table 1. Relay Loadability Evaluation Criteria  |   |        |  |   |
|---|---|--------|--|---|
| Application   | Relay Type  | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria   |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer | 17     | 1.0 per unit of the line nominal voltage | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | If the relay is installed on the generator-side of the GSU transformer use Option 10                                      |        |  |   |
| <b>The same application continues on the next page with a different relay type</b>  |   |        |  |   |

| Table 1. Relay Loadability Evaluation Criteria  |  |        |  |  |
|---|--|--------|--|--|
| Application   | Relay Type   | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations) | Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer<br><br>If the relay is installed on the generator-side of the GSU transformer use Option 11 | 18     | 1.0 per unit of the line nominal voltage | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | <b>The same application continues on the next page with a different relay type</b>   |        |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |  |        |  |   |
|--|--|--------|--|---|
| Application  | Relay Type   | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria   |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p> | <p>Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 12</p> | 19     | 1.0 per unit of the line nominal voltage | <p>The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)</p> |
| End of Table 1   |  |        |  |   |



**Rationale:**

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

**Rationale for R1:**

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

**Version History**

| Version | Date            | Action                                | Change Tracking  |
|---------|-----------------|---------------------------------------|--|
| 1       | August 15, 2013 | Adopted by NERC Board of Trustees     | New  |
| 1(X)    | TBD             | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. **Title:** Generator Relay Loadability
- 2. **Number:** PRC-025-1(X)

**Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

3.1. **Functional Entities:**

- 3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.
- 3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.
- 3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.2. **Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator’s system restoration plan:

- 3.2.1 Generating unit(s).
- 3.2.2 Generator step-up (i.e., GSU) transformer(s).
- 3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.<sup>1</sup>
- 3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
- 3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

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<sup>1</sup> These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1(X) Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

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disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.<sup>2</sup>

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

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

Deleted: See Implementation Plan¶

### B. Requirements and Measures

- R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.  
*[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
- M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1(X) – Attachment 1: Relay Settings.

### C. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Enforcement Authority

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

<sup>2</sup> Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

**1.2. Evidence Retention**

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

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None

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**Table of Compliance Elements**

| R #       | Time Horizon       | VRF  | Violation Severity Levels |              |          |   |
|-----------|--------------------|------|---------------------------|--------------|----------|---|
|           |                    |      | Lower VSL                 | Moderate VSL | High VSL | Severe VSL  |
| <b>R1</b> | Long-Term Planning | High | N/A                       | N/A          | N/A      | The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with <i>PRC-025-1(X) – Attachment 1: Relay Settings</i> , on an applied load-responsive protective relay. |

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

## PRC-025-1(X) – Attachment 1: Relay Settings

### Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

### Generators

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

### Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

### Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

### Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.<sup>3</sup>
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Deleted: Special Protection System

### Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

<sup>3</sup> IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

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loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.



| Table 1. Relay Loadability Evaluation Criteria   |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system | 1a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 1c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 100% of the maximum gross Mvar output during field-forcing as determined by simulation      |  |
| <b>The same application continues on the next page with a different relay type</b>                             |  |           |   |   |  |

<sup>4</sup> Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

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| Table 1. Relay Loadability Evaluation Criteria   |   |   |  |  |  |
|--|---|---|--|--|--|
| Application  | Relay Type  | Option  | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |  |
| Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 2a  | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b>   |  |  |  |
|  |   | 2b  | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  | <b>OR</b>   |   |  |  |  |
|  | 2c  | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and<br>(2) Reactive Power output – 100% of the maximum gross Mvar output during field-forcing as determined by simulation |  |  |
| <b>The same application continues with a different relay type below</b>  |   |   |  |  |  |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 3   | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |  |
| <b>A different application starts on the next page</b>   |   |   |  |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |   |        |   |  |
|--|---|--------|---|--|
| Application  | Relay Type  | Option | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |
| Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources | Phase distance relay (21) – directional toward the Transmission system                                  | 4      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|  | Phase time overcurrent relay (51) or (51V-R) – voltage-restrained                                       | 5      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|  | Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage) | 6      | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | Voltage control setting shall be set less than 75% of the calculated generator bus voltage   |
| A different application starts on the next page  |   |        |   |  |

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| Table 1. Relay Loadability Evaluation Criteria                                     |  |           |   |  |  |
|--|--|-----------|---|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 14 | 7a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |  |  |
|  |  | 7c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation      |  |
| <b>The same application continues on the next page with a different relay type</b> |  |           |   |  |  |

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| Table 1. Relay Loadability Evaluation Criteria                                     |   |           |   |   |  |
|--|---|-----------|---|---|--|
| Application  | Relay Type  | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators               | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 15 | 8a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |   | <b>OR</b> |   |   |  |
|  |   | 8c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation      |  |
| <b>The same application continues on the next page with a different relay type</b> |   |           |   |   |  |

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| Table 1. Relay Loadability Evaluation Criteria                       |  |           |   |   |  |
|--|--|-----------|---|---|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria   |  |
| Generator step-up transformer(s) connected to synchronous generators | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 16 | 9a        | Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9b        | Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)   | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |  |
|  |  | <b>OR</b> |   |   |  |
|  |  | 9c        | Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation      |  |
| <b>A different application starts on the next page</b>               |  |           |   |   |  |

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| Table 1. Relay Loadability Evaluation Criteria  |  |        |  |  |
|---|--|--------|--|--|
| Application   | Relay Type   | Option | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 17 | 10     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer  | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)    |
|   | Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer<br>If the relay is installed on the high-side of the GSU transformer use Option 18                                      | 11     | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | <b>The same application continues on the next page with a different relay type</b>   |        |  |  |

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| Table 1. Relay Loadability Evaluation Criteria  |  |           |   |  |
|---|--|-----------|---|--|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>  | Pickup Setting Criteria  |
| Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) | Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer<br><br>If the relay is installed on the high-side of the GSU transformer use Option 19 | 12        | Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
| <b>A different application starts below</b>   |  |           |   |  |
| Unit auxiliary transformer(s) (UAT)   | Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.   | 13a       | 1.0 per unit of the winding nominal voltage of the unit auxiliary transformer   | The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating  |
|   |  | <b>OR</b> |   |  |
|   |  | 13b       | Unit auxiliary transformer bus voltage corresponding to the measured current  | The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner  |
| <b>A different application starts on the next page</b>  |  |           |   |  |



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| Table 1. Relay Loadability Evaluation Criteria   |  |           |  |  |
|--|--|-----------|--|--|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria  |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators | Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer | 14a       | 0.85 per unit of the line nominal voltage  | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |
|  |  | <b>OR</b> |  |  |
|  | If the relay is installed on the generator-side of the GSU transformer use Option 7  | 14b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The impedance element shall be set less than the calculated impedance derived from 115% of:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |
| <b>The same application continues on the next page with a different relay type</b>   |  |           |  |  |

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| Table 1. Relay Loadability Evaluation Criteria   |  |           |  |   |
|--|--|-----------|--|---|
| Application  | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria   |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators | Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer | 15a       | 0.85 per unit of the line nominal voltage  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |
|  |  | <b>OR</b> |  |   |
|  | If the relay is installed on the generator-side of the GSU transformer use Option 8  | 15b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation       |
| <b>The same application continues on the next page with a different relay type</b>   |  |           |  |   |

| Table 1. Relay Loadability Evaluation Criteria  |  |           |  |   |
|---|--|-----------|--|---|
| Application   | Relay Type   | Option    | Bus Voltage <sup>4</sup>   | Pickup Setting Criteria   |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators | Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer | 16a       | 0.85 per unit of the line nominal voltage  | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor |
|   |  | <b>OR</b> |  |   |
|   | If the relay is installed on the generator-side of the GSU transformer use Option 9  | 16b       | Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing | The overcurrent element shall be set greater than 115% of the calculated current derived from:<br>(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and<br>(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation      |

A different application starts on the next page

| Table 1. Relay Loadability Evaluation Criteria  |   |        |  |   |
|---|---|--------|--|---|
| Application   | Relay Type  | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria   |
| Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations) | Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer | 17     | 1.0 per unit of the line nominal voltage | The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|   | If the relay is installed on the generator-side of the GSU transformer use Option 10                                      |        |  |   |
| <p><b>The same application continues on the next page with a different relay type</b></p>   |   |        |  |   |

**PRC-025-1(X) — Generator Relay Loadability**

| Table 1. Relay Loadability Evaluation Criteria   |   |        |  |  |
|--|---|--------|--|--|
| Application  | Relay Type  | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria  |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p> | <p>Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer</p> | 18     | 1.0 per unit of the line nominal voltage | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
|  | <p><b>The same application continues on the next page with a different relay type</b></p>   |        |  |  |

| Table 1. Relay Loadability Evaluation Criteria   |  |        |  |  |
|--|--|--------|--|--|
| Application  | Relay Type   | Option | Bus Voltage <sup>4</sup>                 | Pickup Setting Criteria  |
| <p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p> | <p>Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 12</p> | 19     | 1.0 per unit of the line nominal voltage | The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices) |
| End of Table 1   |  |        |  |  |

**PRC-025-1(X)— Generator Relay Loadability**

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**Rationale:**

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

**Rationale for R1:**

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

**Version History**

| Version     | Date            | Action                                       | Change Tracking   |
|-------------|-----------------|--|---|
| 1           | August 15, 2013 | Adopted by NERC Board of Trustees            | New   |
| <u>1(X)</u> | <u>TBD</u>      | <u>Adopted by the NERC Board of Trustees</u> | <u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u> |

## A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-2a(X)
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Purchasing Selling Entities.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

## C. Measures

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.



**1.2. Compliance Monitoring Period and Reset Time Frame**

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

**1.3. Data Retention**

Not specified.

**1.4. Additional Compliance Information**

Not specified.

2. Violation Severity Levels:

| R# | Lower  | Moderate | High | Severe   |
|----|--|----------|------|--|
| R1 | N/A  | N/A      | N/A  | The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.             |
| R2 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |
| R3 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |

**E. Regional Variances**

None identified.

**Version History**

| Version | Date             | Action  | Change Tracking  |
|---------|------------------|---|--|
| 0       | April 1, 2005    | Effective Date  | New  |
| 0       | August 8, 2005   | Removed “Proposed” from Effective Date  | Errata   |
| 1       |                  | Removed the Reliability Coordinator from the list of responsible functional entities<br>Deleted R1 and R1.1<br>Modified M1 to omit the reference to the Reliability Coordinator<br>Deleted VSLs for R1 and R1.1 | Revised  |
| 2       | October 17, 2008 | Adopted by NERC Board of Trustees   | New  |
| 2       | March 17, 2011   | Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)   |  |
| 2a      | April 21, 2011   | Added FERC approved Interpretation  |  |
| 2a(X)   | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Attachment 1-TOP-005**

**Electric System Reliability Data**

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

- 1.** The following information shall be updated at least every ten minutes:
  - 1.1.** Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
    - 1.1.1** Status.
    - 1.1.2** MW or ampere loadings.
    - 1.1.3** MVA capability.
    - 1.1.4** Transformer tap and phase angle settings.
    - 1.1.5** Key voltages.
  - 1.2.** Generator data.
    - 1.2.1** Status.
    - 1.2.2** MW and MVAR capability.
    - 1.2.3** MW and MVAR net output.
    - 1.2.4** Status of automatic voltage control facilities.
  - 1.3.** Operating reserve.
    - 1.3.1** MW reserve available within ten minutes.
  - 1.4.** Balancing Authority demand.
    - 1.4.1** Instantaneous.
  - 1.5.** Interchange.
    - 1.5.1** Instantaneous actual interchange with each Balancing Authority.
    - 1.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
    - 1.5.3** Interchange Schedules for the next 24 hours.
  - 1.6.** Area Control Error and frequency.
    - 1.6.1** Instantaneous area control error.
    - 1.6.2** Clock hour area control error.
    - 1.6.3** System frequency at one or more locations in the Balancing Authority.
- 2.** Other operating information updated as soon as available.
  - 2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
  - 2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
  - 2.3.** Forecast peak demand for current day and next day.
  - 2.4.** Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded Remedial Action Schemes.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Appendix 2

| Requirement Number and Text of Requirement  |
|---|
| <p><b>TOP-005-1 Requirement R3<sup>1</sup></b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12</b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation   |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>  |

<sup>1</sup> In the current version of the Standard (TOP-005-2a), this requirement is R2.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## Standard TOP-005-2a(X) — Operational Reliability Information

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### A. Introduction

1. **Title:** Operational Reliability Information
2. **Number:** TOP-005-2a(X)
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Purchasing Selling Entities.
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**Deleted: Proposed**

**Deleted:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

### B. Requirements

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

### C. Measures

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.



**Standard TOP-005-2a(X) — Operational Reliability Information**

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**1.2. Compliance Monitoring Period and Reset Time Frame**

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

**1.3. Data Retention**

Not specified.

**1.4. Additional Compliance Information**

Not specified.

**Standard TOP-005-2a(X) — Operational Reliability Information**

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**2. Violation Severity Levels:**

| <b>R#</b> | <b>Lower</b>   | <b>Moderate</b> | <b>High</b> | <b>Severe</b>  |
|-----------|--|-----------------|-------------|--|
| R1        | N/A  | N/A             | N/A         | The ISN data recipient failed to sign the NERC Confidentiality Agreement for "Electric System Reliability Data".             |
| R2        | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A             | N/A         | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |
| R3        | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A             | N/A         | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |

**Standard TOP-005-2a(X) — Operational Reliability Information**

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**E. Regional Variances**

None identified.

**Version History**

| Version               | Date                | Action  | Change Tracking  |
|-----------------------|---------------------|---|--|
| 0                     | April 1, 2005       | Effective Date  | New  |
| 0                     | August 8, 2005      | Removed “Proposed” from Effective Date  | Errata   |
| 1                     |                     | Removed the Reliability Coordinator from the list of responsible functional entities<br>Deleted R1 and R1.1<br>Modified M1 to omit the reference to the Reliability Coordinator<br>Deleted VSLs for R1 and R1.1 | Revised  |
| 2                     | October 17, 2008    | Adopted by NERC Board of Trustees   | New  |
| 2                     | March 17, 2011      | Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)   |  |
| 2a                    | April 21, 2011      | Added FERC approved Interpretation  |  |
| <a href="#">2a(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a>   | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

**Attachment 1-TOP-005**

**Electric System Reliability Data**

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

1. The following information shall be updated at least every ten minutes:
  - 1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
    - 1.1.1 Status.
    - 1.1.2 MW or ampere loadings.
    - 1.1.3 MVA capability.
    - 1.1.4 Transformer tap and phase angle settings.
    - 1.1.5 Key voltages.
  - 1.2. Generator data.
    - 1.2.1 Status.
    - 1.2.2 MW and MVAR capability.
    - 1.2.3 MW and MVAR net output.
    - 1.2.4 Status of automatic voltage control facilities.
  - 1.3. Operating reserve.
    - 1.3.1 MW reserve available within ten minutes.
  - 1.4. Balancing Authority demand.
    - 1.4.1 Instantaneous.
  - 1.5. Interchange.
    - 1.5.1 Instantaneous actual interchange with each Balancing Authority.
    - 1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
    - 1.5.3 Interchange Schedules for the next 24 hours.
  - 1.6. Area Control Error and frequency.
    - 1.6.1 Instantaneous area control error.
    - 1.6.2 Clock hour area control error.
    - 1.6.3 System frequency at one or more locations in the Balancing Authority.
2. Other operating information updated as soon as available.
  - 2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.
  - 2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.
  - 2.3. Forecast peak demand for current day and next day.
  - 2.4. Forecast changes in equipment status.

**Standard TOP-005-2a(X) — Operational Reliability Information**

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- 2.5. New facilities in place.
- 2.6. New or degraded [Remedial Action Schemes](#).
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Deleted: special protection system

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Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3<sup>1</sup></b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or degraded Remedial Action Schemes. [Underline added for emphasis.]</i></p>  |
| <p><b>IRO-005-1 Requirement R12</b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected. [Underline added for emphasis.]</p>   |
| <p><b>PRC-012-0(X) Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p>   |
| <p><b>Background Information for Interpretation</b></p> <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p> |

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<sup>1</sup> In the current version of the Standard (TOP-005-2a), this requirement is R2.

**Standard TOP-005-2a(X) — Operational Reliability Information**

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

**Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

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## A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2.** Be conducted annually unless changes to system conditions do not warrant such analyses.



- R1.3.3.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
  - R1.3.4.** Have established normal (pre-contingency) operating procedures in place.
  - R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(X)\_R1 and TPL-001-0.1(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(X)\_R3.

### **D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|------------------|---|--|
| 0              | April 1, 2005    | Effective Date  | New  |
| 0              | February 8, 2005 | BOT Approval  | Revised  |
| 0              | June 3, 2005     | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata   |
| 0              | July 24, 2007    | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata   |
| 0.1            | October 29, 2008 | BOT adopted errata changes; updated version number to "0.1"       | Errata   |
| 0.1            | May 13, 2009     | FERC Approved – Updated Effective Date                            | Revised  |
| 0.1(X)         | TBD              | Adopted by the NERC Board of Trustees                             | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                      |
|--|--|---|--|----------------------|
|  |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers   | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>   | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>  | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>   | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |

**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

|  |   |                |                |                         |                |  |
|--|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|  | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit  | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Standard TPL-001-0.1(X) — System Performance Under Normal Conditions

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### A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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### B. Requirements

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
- R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2.** Be conducted annually unless changes to system conditions do not warrant such analyses.

## Standard TPL-001-0.1(X) — System Performance Under Normal Conditions

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- R1.3.3.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
  - R1.3.4.** Have established normal (pre-contingency) operating procedures in place.
  - R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(X)\_R1 and TPL-001-0.1(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(X)\_R3.

### D. Compliance

**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version           | Date             | Action  | Change Tracking   |
|-------------------|------------------|---|---|
| 0                 | April 1, 2005    | Effective Date  | New   |
| 0                 | February 8, 2005 | BOT Approval  | Revised   |
| 0                 | June 3, 2005     | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata  |
| 0                 | July 24, 2007    | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata  |
| 0.1               | October 29, 2008 | BOT adopted errata changes; updated version number to "0.1"       | Errata  |
| 0.1               | May 13, 2009     | FERC Approved – Updated Effective Date                            | Revised   |
| <del>0.1(X)</del> | <del>TBD</del>   | <del>Adopted by the NERC Board of Trustees</del>                  | <del>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</del> |

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**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                      |
|--|--|---|--|----------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers   | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing <sup>c</sup> :<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>   | No<br>No<br>No<br>No |
|  | Loss of an Element without a Fault<br>Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>d</sup>  | No                   |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>d</sup>  | No                   |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>d</sup>  | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup>   | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup> | No<br>No<br>No<br>No |



**Standard TPL-001-0.1(X) — System Performance Under Normal Conditions**

|   |   |                |                |                         |                |  |
|---|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>  | <p>3Ø Fault, with Delayed Clearing<sup>c</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>c</sup>:</p> <ol style="list-style-type: none"> <li>Breaker (failure or internal Fault)</li> <li>Loss of towerline with three or more circuits</li> <li>All transmission lines on a common right-of way</li> <li>Loss of a substation (one voltage level plus transformers)</li> <li>Loss of a switching station (one voltage level plus transformers)</li> <li>Loss of all generating units at a station</li> <li>Loss of a large Load or major Load center</li> <li>Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |                |                |                         |                |  |

- Deleted: Special Protection System
- Deleted: (or remedial action scheme)
- Deleted: Special Protection System
- Deleted: (or Remedial Action Scheme)

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**A. Introduction**

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0b(X)
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.

## **Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

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- R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
- R1.3.5.** Have all projected firm transfers modeled.
- R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.
- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0b(X)\_R1 and TPL-002-0b(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0b(X)\_R3.

### **D. Compliance**

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

**Compliance Monitor:** Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|--------------------|--|------------------------|
| 0              | February 8, 2005   | Adopted by NERC Board of Trustees  | New                    |
| 0              | April 1, 2005      | Effective Date   | New                    |
| 0a             | July 30, 2008      | Adopted by NERC Board of Trustees  | New                    |
| 0a             | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised                |
| 0b             | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation         |
| 0b             | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation         |

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

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|       |     |                                       |  |
|-------|-----|---------------------------------------|--|
| 0b(X) | TBD | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|-------|-----|---------------------------------------|--|

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**Table I. Transmission System Standards — Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

|   |   |                |                |                         |                |  |
|---|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <p>5. Breaker (failure or internal Fault)</p> <hr style="border-top: 1px dashed black;"/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Appendix 1

### **Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### **Requirement R1.3.2**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*



**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2  
Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

## Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p style="padding-left: 40px;"><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| Background Information for Interpretation  |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> <li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li> <li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li> <li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li> </ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> </ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>4. Single Pole (dc) Line</li> </ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| Conclusion   |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

## Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element

### A. Introduction

1. **Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
2. **Number:** TPL-002-0b(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner

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

**Deleted:** Immediately after approval of applicable regulatory authorities.

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

## **Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

- R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
- R1.3.5.** Have all projected firm transfers modeled.
- R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.
- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0b(X)\_R1 and TPL-002-0b(X)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0b(X)\_R3.

### **D. Compliance**

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

**Compliance Monitor:** Regional Reliability Organizations.  
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date               | Action   | Change Tracking |
|---------|--------------------|--|-----------------|
| 0       | February 8, 2005   | Adopted by NERC Board of Trustees  | New             |
| 0       | April 1, 2005      | Effective Date   | New             |
| 0a      | July 30, 2008      | Adopted by NERC Board of Trustees  | New             |
| 0a      | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised         |
| 0b      | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation  |
| 0b      | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation  |

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

|                       |                     |   |  |
|-----------------------|---------------------|---|--|
| <a href="#">0b(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a> | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |
|-----------------------|---------------------|---|--|



**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**Table I. Transmission System Standards — Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                      |
|--|--|---|--|----------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|  | 5. Any two circuits of a multiple circuit towerline <sup>e</sup>   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator  | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
| 7. Transformer   | Yes  | Planned/<br>Controlled <sup>d</sup>   | No   |                      |
| 8. Transmission Circuit  | Yes  | Planned/<br>Controlled <sup>d</sup>   | No   |                      |
| 9. Bus Section   | Yes  | Planned/<br>Controlled <sup>d</sup>   | No   |                      |

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

|   |  |   |
|---|--|---|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>c</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol>   | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas</li> </ul>  |
|   | <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <ul style="list-style-type: none"> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

- Deleted: Special Protection System
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**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**Appendix 1**

**Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

**TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**Requirement R1.3.2**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## **Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

## **Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

### **Requirement R1.3.12**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

#### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

**Appendix 2**

| <b>Requirement Number and Text of Requirement</b>  |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| <b>Background Information for Interpretation</b>   |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"><li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li><li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li><li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li></ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"><li>1. Generator</li><li>2. Transmission Circuit</li><li>3. Transformer</li></ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"><li>4. Single Pole (dc) Line</li></ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| <b>Conclusion</b>  |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

**Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element**

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D). TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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### A. Introduction

1. **Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. **Number:** TPL-003-0b(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner

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

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.



## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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- R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
  - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
  - R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
  - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
  - R1.3.11.** Include the effects of existing and planned control devices.
  - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0b(X)\_R1 and TPL-003-0b(X)\_R2.

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

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- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0b(X)\_R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|------------------|--|------------------------|
| 0              | February 8, 2005 | Adopted by NERC Board of Trustees  | New                    |
| 0              | April 1, 2005    | Effective Date   | New                    |
| 0              | April 1, 2005    | Add parenthesis to item “e” on page 8.   | Errata                 |
| 0a             | July 30, 2008    | Adopted by NERC Board of Trustees  |                        |
| 0a             | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised                |
| 0a             | April 23, 2010   | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation         |
| 0b             | February 7, 2013 | Interpretation adopted by NERC Board of Trustees   |                        |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

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|       |               |  |  |
|-------|---------------|--|--|
| 0b    | June 20, 2013 | FERC order issued approving Interpretation |  |
| 0b(X) | TBD           | Adopted by the NERC Board of Trustees      | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                                |
|--|--|---|--|--------------------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No           |
|  | Single Pole Block, Normal Clearing <sup>e</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>e</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | Bipolar Block, with Normal Clearing <sup>e</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>e</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
| 7. Transformer   | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |
| 8. Transmission Circuit  | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |
| 9. Bus Section   | Yes  | Planned/<br>Controlled <sup>c</sup>   | No   |                                |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

|   |   |              |                |                         |                |  |
|---|---|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <hr/> <p>5. Breaker (failure or internal Fault)</p> <hr/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer  |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## **Appendix 1**

### **Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### **Requirement R1.3.2**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.



**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

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clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(X) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

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<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

### Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

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<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

## Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

### A. Introduction

1. **Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. **Number:** TPL-003-0b(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner

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

Deleted: April 23, 2010

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table I (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

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- R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
  - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
  - R1.3.5.** Have all projected firm transfers modeled.
  - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
  - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
  - R1.3.11.** Include the effects of existing and planned control devices.
  - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0b(X)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0b(X)\_R1 and TPL-003-0b(X)\_R2.

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0b(X)\_R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

**1.** None identified.

**Version History**

| Version | Date             | Action   | Change Tracking |
|---------|------------------|--|-----------------|
| 0       | February 8, 2005 | Adopted by NERC Board of Trustees  | New             |
| 0       | April 1, 2005    | Effective Date   | New             |
| 0       | April 1, 2005    | Add parenthesis to item “e” on page 8.   | Errata          |
| 0a      | July 30, 2008    | Adopted by NERC Board of Trustees  |                 |
| 0a      | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised         |
| 0a      | April 23, 2010   | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation  |
| 0b      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees   |                 |



**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

|                       |                     |   |  |
|-----------------------|---------------------|---|--|
| 0b                    | June 20, 2013       | FERC order issued approving Interpretation            |  |
| <a href="#">0b(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a> | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |  |                                |
|--|--|---|--|--------------------------------|
|  |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers   | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No   | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>   | No<br>No<br>No<br>No           |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>d</sup>  | No                             |
|  | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>d</sup>  | No                             |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>d</sup>  | No                             |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup>   | No<br>No                       |
|  | SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup><br>Planned/<br>Controlled <sup>d</sup> | No<br>No<br>No<br>No           |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

|   |   |                |                |                         |                |  |
|---|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>Breaker (failure or internal Fault)</li> <li>Loss of towerline with three or more circuits</li> <li>All transmission lines on a common right-of way</li> <li>Loss of a substation (one voltage level plus transformers)</li> <li>Loss of a switching station (one voltage level plus transformers)</li> <li>Loss of all generating units at a station</li> <li>Loss of a large Load or major Load center</li> <li>Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |                |                |                         |                |  |

- Deleted: Special Protection System
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- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

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**Appendix 1**

**Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

**TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**Requirement R1.3.2**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, ‘critical system conditions’ in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## **Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

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### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

## **Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

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### **Requirement R1.3.12**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

#### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

| <p>Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee</p>   |   |
|---|---|
| <p><b>Date submitted:</b></p>   | <p>December 12, 2011</p>  |
| <p>The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).</p> |   |
| Standard  | Requirement (and text)  |
| TPL-003-0a  | <p><b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</p>  |
| TPL-003-0a  | <p><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>   |
| TPL-003-0a  | <p><b>R1.5.</b> Consider all contingencies applicable to Category C.</p>  |
| TPL-004-0   | <p><b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.</p> |
| TPL-004-0   | <p><b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| TPL-004-0   | <p><b>R1.4.</b> Consider all contingencies applicable to Category D.</p>  |
| <p>Please explain the clarification needed (as submitted).</p>  |   |
| <p>This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning</p>  |   |

**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(X) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a, Category C and TPL-004-0, Category D) contingencies that would produce the more severe system results or impacts."

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**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

**Question 1**

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

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**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

**Response 1**

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

**Question 2**

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

**Response 2**

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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**Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements**

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

**A. Introduction**

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0a(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

**B. Requirements**

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.

- R1.3.6.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.8.** Include the effects of existing and planned control devices.
- R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

**R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0a(X)\_R1.
- M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0a(X)\_R1.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### **1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

##### **1.3. Data Retention**

None specified.

##### **1.4. Additional Compliance Information**

None.

#### **2. Levels of Non-Compliance**

- 2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.
- 2.2. Level 2:** Not applicable.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** Not applicable.

### **E. Regional Differences**

- 1.** None identified.

## Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

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### Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 0       | April 1, 2005    | Effective Date                                   | New  |
| 0a      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees |  |
| 0a      | June 20, 2013    | Interpretation approved in FERC order            |  |
| 0a(X)   | TBD              | Adopted by the NERC Board of Trustees            | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |   |                      |
|--|--|---|---|----------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers  | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No  | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>  | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>   | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section<br>2. Breaker (failure or internal Fault)   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No             |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>   | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |

## Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

|   |   |  |
|---|---|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|---|---|--|

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.



**Appendix 1**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

## Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

## Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## **Standard TPL-004-0a(x) — System Performance Following Extreme BES Events**

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

## Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

### A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0a(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** This standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Deleted: April 1, 2005

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.

**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

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- R1.3.6.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.8.** Include the effects of existing and planned control devices.
- R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

- R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

**C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0a(X)\_R1.
- M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0a(X)\_R1.

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**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.  
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.
- 2.2. Level 2:** Not applicable.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** Not applicable.

**E. Regional Differences**

- 1.** None identified.

**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

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**Version History**

| <b>Version</b>        | <b>Date</b>         | <b>Action</b>   | <b>Change Tracking</b>   |
|-----------------------|---------------------|---|--|
| 0                     | April 1, 2005       | Effective Date  | New  |
| 0a                    | February 7, 2013    | Interpretation adopted by NERC Board of Trustees      |  |
| 0a                    | June 20, 2013       | Interpretation approved in FERC order                 |  |
| <a href="#">0a(X)</a> | <a href="#">TBD</a> | <a href="#">Adopted by the NERC Board of Trustees</a> | <a href="#">Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</a> |



**Standard TPL-004-0a(X) — System Performance Following Extreme BES Events**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>e</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>e</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>e</sup> :   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>d</sup>                                      | No                   |

**Standard TPL-004-0a(x) — System Performance Following Extreme BES Events**

|  |  |  |
|--|--|--|
| <p><b>D<sup>d</sup></b><br/>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>c</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol>   | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|  | <p>3Ø Fault, with Normal Clearing<sup>c</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |  |

- Deleted: Special Protection System
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- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**Standard TPL-004-0a(x) — System Performance Following Extreme BES Events**

**Appendix 1**

| <p>Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee</p>   |  |
|---|--|
| <p><b>Date submitted:</b></p>   | <p>December 12, 2011</p>   |
| <p>The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).</p> |  |
| Standard  | Requirement (and text)   |
| TPL-003-0a  | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a  | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a  | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0   | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0   | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0   | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |
| <p>Please explain the clarification needed (as submitted).</p>  |  |
| <p>This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.</p>  |  |

## Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

## Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

## Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

# Unofficial Comment Form

## Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the **proposed definition of Remedial Action Scheme (RAS)**. The electronic comment form must be completed by **8 p.m. Eastern, Tuesday, October 14, 2014**.

If you have questions, please contact Al McMeekin, NERC Standards Developer by email at [Al.McMeekin@nerc.net](mailto:Al.McMeekin@nerc.net) or by telephone at (404) 446-9675.

The project page may be accessed by [clicking here](#).

### Background Information

The existing NERC Glossary of Terms definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS or RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS or RAS. The actions listed in the definition of “Special Protection System” and “Remedial Action Scheme” are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term; i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

**Note:** The term “**Remedial Action Scheme**” (“**RAS**”) is and will be used throughout the documents associated with this Project to reflect the proposed retirement of the term “Special Protection System” (“SPS”).

Initially, the term SPS will be replaced with RAS in only those Reliability Standards that are currently fully implemented. There are a few standards in implementation that NERC determined could be modified now, they are PRC-005-2, PRC-005-3, and PRC-024-1. For those Reliability Standards that contain references to SPS and that are still in the implementation phase or under development, the transition to RAS will occur after full implementation of the standard is completed. This approach will prevent any possible timing issues associated with the transition. To ensure there is no gap in the standards, the term SPS will not be retired until the last reference to SPS is replaced in the full body of Reliability Standards. Consequently, for a short time, there will be two definitions – one for SPS and one for RAS. Where SPS is used in a requirement, entities will continue to utilize the definition of SPS. Where RAS is used, entities will use the definition of RAS.

The Project 2010-05.2 Special Protection Systems Standard Drafting Team (SPSSDT) posted the first draft of the proposed RAS definition for comment from June 11, 2014 to July 25, 2014. The drafting team



considered all stakeholder comments and suggestions and revised the draft definition. The following is a summary of changes the drafting team made:

Changed the phrase “curtailing or tripping generation or other sources” to “adjusting or tripping generation (MW and Mvar)”

Changed the phrase “curtailing or tripping load” to “tripping load”

Changed the introductory sentence to the objectives from: “RAS accomplish one or more of the following objectives” to “RAS accomplish objectives such as” because the objective list is no longer all inclusive

Inserted “Bulk Electric System” (BES) as a qualifier in the pertinent objectives

Removed the last objective: “Address other Bulk Electric System (BES) reliability concerns” because it was deemed overly broad

Revised the fifth objective to read: “Limit the impact of Cascading or extreme event”

Removed the sentence: “These schemes are not Protection Systems; however, they may share components with Protection Systems.”

Added a new exclusion (a) that reads: “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements”

Combined exclusions (b) and (c) to read: “Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays”

Changed exclusion (d) from “Autoreclosing schemes” to “Automatic Reclosing schemes” to be in alignment with Reliability Standard PRC-05-3

In exclusion (e), changed the term “high voltage” to “overvoltage”

In exclusion (f), removed the term “generation excitation”

In exclusion (k), replaced “operator” with the defined term “System Operator”

Added a new exclusion (n) that reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing”

Updated the Background and FAQ document to reflect the changes and additions made to the proposed definition.

Updated Implementation Plan:

- added a specific Effective Date for PRC-024-1
- removed standards that are currently in implementation phase (these standards will be modified at a later date)
- removed retirement of “Special Protection System” (SPS) (the SPS definition will be needed until all references to SPS can be replaced with “Remedial Action Scheme” (RAS))

Updated the “Revised Reliability Standards for the Revised Definition of RAS” to reflect the reduction in standards currently being modified

### **Additional 45-day Formal Comment and Ballot Period**

The SPSSDT is soliciting stakeholder feedback on the second draft of the RAS definition. The [electronic comment form](#) must be completed by **8 p.m. Eastern Tuesday, October 14, 2014**.

Please enter comments in simple text format, as bullets, numbers, and **special formatting will not be retained** (even if it appears to transfer formatting when copying from the unofficial Word version of the form into the official electronic comment form). If you enter extra carriage returns, bullets, automated numbering, symbols, bolding, italics, or any other formatting, that formatting will not be retained when you submit your comments.

- Separate discrete comments by idea, e.g., preface with (1), (2), etc.
- Use brackets [] to call attention to suggested inserted or deleted text.
- Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.
- **Do not use** formatting such as extra carriage returns, bullets, automated numbering, bolding, or italics.
- **Please do not repeat other entity’s comments.** Select the appropriate item to support another entity’s comments. An opportunity to enter additional or exception comments will be available.
- If supporting other’s comments, be sure the other party submits comments.

**Question:**

1. Do you agree with the revised definition of a Remedial Action Scheme (RAS)? If not, please provide the basis for your disagreement and your proposed revisions.

Yes

No

Comments:

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# “Remedial Action Scheme” Definition Development Background and Frequently Asked Questions

Project 2010-05.2 – Special Protection Systems

August 2014

**RELIABILITY | ACCOUNTABILITY**



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## Introduction

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The Project 2010-05.2 – Special Protection Systems Standard Drafting Team (SDT) developed this background and Frequently Asked Questions (FAQ) document to explain the key concepts incorporated into the revised definition, as well as the team’s approach and intent. This document will remain available as part of the official project record for the Remedial Action Scheme (RAS) definition. In addition to providing individual responses to commenters for the first formal comment period conducted June-July, 2014, the drafting team has updated this Frequently Asked Questions (FAQ) document to reflect all revisions made to the RAS definition based on stakeholder feedback.

Contact the Standards Developer, Al McMeekin, at 404-446-9675 or at [al.mcmeekin@nerc.net](mailto:al.mcmeekin@nerc.net) with any comments or questions.

## Background and FAQ – RAS Definition Development

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### Existing Glossary of Terms Used in NERC Reliability Standards Definitions

The existing Glossary of Terms Used in NERC Reliability Standards defines **SPS** or **RAS** as: “An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.”

The Glossary of Terms Used in NERC Reliability Standards defines a **Protection System** as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

### Revision of the Glossary of Terms Used in NERC Reliability Standards Definition

#### Purpose of Revision of the Glossary of Terms Used in NERC Reliability Standards SPS or RAS

The existing Glossary of Terms Used in NERC Reliability Standards definition for an SPS/RAS lacks the clarity and specificity necessary to consistently identify what equipment or schemes qualify as an SPS/RAS across the eight NERC Regions. This confusion leads to inconsistent application of the SPS/RAS-related NERC Reliability Standards.

The existing definition also lacks clarity in the actions stipulated as characteristics of an SPS/RAS. The actions listed in the definition are so broad that the definition may unintentionally include schemes whose purpose is not expressly related to preserving system reliability in response to predetermined system conditions. Inclusion of any scheme taking “corrective action other than isolation of faulted components to maintain system reliability” could be interpreted to mean that devices such as voltage regulators and switching controls for shunt capacitors should be included. This inclusion would then make these devices subject to requirements such as those addressing single-component failure considerations (sometimes referred to as redundancy considerations) in the SPS/RAS-related NERC Reliability Standards.

#### Recommendation to Change the Term to RAS Only

Currently, both terms, SPS and RAS, are used in the eight NERC Regions. The SDT contends that a single term promotes consistency. The SDT therefore recommends that the term RAS be retained as the industry-recognized term and that the term SPS ultimately be retired. The term RAS is more descriptive of the purpose for which the scheme is installed.

The term RAS also eliminates the confusion associated with the two defined terms, “Special Protection System” and “Protection System.” The inclusion of Protection System in the term Special Protection System implies that SPS are a subset of Protection Systems.

### Effects of Using Only the Term RAS in the Existing NERC Reliability Standards

The existing NERC Reliability Standards and Glossary of Terms Used in NERC Reliability Standards use the terms, SPS and RAS interchangeably. In most cases, both terms are included in the standards and written as: “SPS or RAS.” The SDT evaluated the existing standards and recommended any necessary revisions to retain the single term “RAS”. Many of the same changes would be required regardless of which single term is retained. A summary of the occurrences of the terms is included in the posted document *Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards*.

## Proposed Definition of RAS

**Remedial Action Scheme:** A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic Reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations



- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Exclusion List Explanations

- a. **Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes the isolation of faulted components because that is a protective function. The SDT accepts this exclusion consistent with industry practice.

- b. **Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes UFLS and UVLS because they are protective functions that have unique design and implementation considerations that are covered by NERC Reliability Standards PRC-006-1 and PRC-010-1. This exclusion emphasizes “distributed” UVLS relays to highlight that the exclusion covers UVLS Programs. The SDT accepts this exclusion consistent with industry practice.

Centrally controlled undervoltage-based load shedding is a RAS.

- c. **Out-of-step tripping and power swing blocking**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes out-of-step relaying because it is a protective function. The SDT maintained the exclusion but changed the wording from “out-of-step relaying” to “out-of-step tripping and power swing blocking” to reflect current industry terminology.

- d. **Automatic Reclosing schemes**

Automatic reclosing schemes, whether single-pole or three-pole, are used to minimize system impacts and restoration efforts by System Operators. Automatic reclosing, in itself, is not a RAS; however, if integrated into a larger scheme that performs additional corrective actions to accomplish the objective(s) listed in the RAS definition, then it would be part of a RAS. For example, a scheme that rejects or runs back generation to avoid instability or thermal overloads in addition to initiating automatic reclosing would constitute a RAS. The drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) Automatic Reclosing; however, system reconfiguration which transfers the load to another source typically would be a RAS.

- e. **Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service**

Schemes applied on a single Element to protect it from damage from non-Fault conditions are protective functions and are not RAS. The SDT accepts this exclusion consistent with industry practice.

- f. **Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated**

Controllers that switch or regulate these devices are not RAS. The SDT accepts this exclusion consistent with industry practice. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations.

**g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device**

The purpose of such controllers is to switch shunt devices to restore an acceptable operating range of a single FACTS device. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations. The SDT accepts this exclusion consistent with industry practice.

**h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched**

Schemes or controllers that assist a System Operator in coordinating the switching of shunt reactors and shunt capacitors that would otherwise be manually switched are not remedial in the sense of being mitigations in response to predetermined System conditions, but are for general application to all System conditions, e.g. optimizing voltage profiles or minimizing losses. The SDT accepts this exclusion consistent with industry practice.

**i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open**

When one end of a line is open, unacceptable voltage levels can occur. Opening the remote terminal(s) to de-energize the transmission line removes this voltage rise. Alternatively, restoration conditions may require energization or synchronizing at a specific terminal. These schemes have not historically been regarded as RAS, and the SDT accepts this exclusion consistent with industry practice.

**j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)**

These schemes are designed to protect load in an electrical island that might otherwise operate at an off-nominal frequency or voltage, or facilitate restoration. Actions taken on islanded facilities will not impact the interconnected BES because the facilities are isolated. The SDT accepts this exclusion consistent with industry practice.

**k. Automatic sequences that proceed when manually initiated solely by a System Operator**

Automated sequences created to simplify the actions of a System Operator are not RAS because the decision to activate a specific sequence is left to the System Operator. If the automated sequence fails to execute correctly, the System Operator has the option to manually set those actions in motion. The SDT accepts this exclusion consistent with industry practice.

The arming of a RAS by a System Operator is not the same as manual initiation of an automatic sequence. Arming enables the scheme but the RAS must still detect the critical conditions it was designed to mitigate and then take action.

**l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations**

Modulation of HVdc and FACTS via supplementary controls is occasionally used for damping local or inter-area oscillations. It is similar in function to a Power System Stabilizer (PSS), which is a component of excitation controls in a generating unit. PSS are also not classified as RAS. The SDT accepts these HVdc and FACTS exclusions consistent with industry practice.

**m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities; (e.g., currents or torsional oscillations)**

Historically, SSR protection schemes that directly detect sub-synchronous quantities and the related mitigation are not RAS. The SDT accepts this exclusion consistent with industry practice.

However, SSR protection schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

**n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing**

These traditional generator and turbine controls are not RAS. The SDT accepts this exclusion consistent with industry practice.

## Explanations Regarding Changes from the Exclusion List Cited in the SAMS-SPCS Report

The SDT revised the straw man definition proposed in the SAMS-SPCS report; however, the proposed definition is consistent with the SAMS-SPCS intent. As a result of the revisions, it is no longer necessary to explicitly state the following exclusions.

### 1. Schemes that prevent high line voltage by automatically switching the affected line

These schemes are now addressed by exclusion (e) (protection from overvoltage) and exclusion (i) (automatic de-energization of a line when one end is open) in the proposed definition.

### 2. Protection schemes that operate local breakers other than those on the faulted circuit to facilitate Fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a Fault or to reduce fault duty

These schemes are now addressed by exclusion (a) in the proposed definition.

### 3. Blanket exclusion for SSR protection schemes

The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

### 4. A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

These schemes are now addressed by exclusion (a) in the proposed definition.

## Frequently Asked Questions

### What is the relationship between a Remedial Action Scheme and a Protection System?

The existing NERC Glossary of Terms definition of a Protection System is a component-based definition that was developed in conjunction with NERC Reliability Standard PRC-005-2 Protection System Maintenance. The definition lists components such as “protective relays which respond to electrical quantities” that represent the building blocks of a Protection System. All protective schemes include some combination of these building blocks but not necessarily all of them, for example, many protective schemes do not have the “communications systems...” component. In other cases, protective schemes like RAS may have all of the Protection System components as well as other pieces of equipment such as programmable logic controllers.

### Why does the proposed definition have an exclusion list?

The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS.

### Why did the SDT not propose a screening process to identify RAS?

The SDT contends that a comprehensive definition with specific exclusions is the best way to achieve consistency and immediacy in RAS identification. The SDT asserts that a study-based screening process would be labor-intensive and dependent on assumptions that could vary among the entities performing the studies.

### Why does the proposed definition not include the classification types suggested in the SPCS-SAMS report?

The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided

not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.

**Why did the SDT not specifically reference the Transmission Planning (TPL) standards in the proposed definition?**

The SDT acknowledges that many RAS are installed to address the performance requirements of the TPL standards; however, they are also installed to address other reliability concerns.

**Would automatic actions taken by an Energy Management System (EMS), Supervisory Control and Data Acquisition (SCADA), or Distribution Control System (DCS) be considered a RAS?**

The above-mentioned control systems support and enable grid operations by issuing control commands mostly to geographically distributed power System devices. In this normal application, e.g. automatic generation control (AGC), these systems are not considered to be RAS. However, if these systems are configured to detect predetermined conditions and take corrective actions consistent with the RAS definition, these automatic functions (not the entire EMS) would be considered to be part of a RAS. The identification of RAS is not dependent upon the specific hardware or platform utilized in the scheme. For example, an automatic UVLS scheme centrally controlled through an EMS would be a RAS.

**What are the Implementation Plan time frames?**

The effective date of the RAS definition as noted in the Implementation Plan is the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. The drafting team notes that RAS owners could use this time to evaluate their existing schemes for determining whether they are RAS, based on the new definition.

The Implementation Plan also provides owners of newly identified RAS twenty-four (24) calendar months beyond the effective date of the definition (i.e., at least 36 months after approval by a governmental authority) to be fully compliant with the existing standards applicable to the revised definition of Remedial Action Scheme. The drafting team contends that this time frame provide entities sufficient time to transition schemes to RAS and become compliant with the revised standards outlined in the Implementation Plan.

Note: These timeframes are not applicable to new RAS implemented subsequent to the effective date of the new definition. New RAS must comply with all applicable standards as they are implemented.

**Coordination with Project 2008-02 – Undervoltage Load Shedding**

As part of the development of PRC-010-1, the Project 2008-02 UVLS SDT is introducing a new NERC Glossary term, UVLS Program, to clearly establish applicability of PRC-010-1:

**Undervoltage Load Shedding Program (UVLS Program):** An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.

Note that the definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, centrally controlled undervoltage-based load shedding should be subject to RAS-related Reliability Standards.

The Project 2010-05.2 SPS SDT agrees with the Project 2008-02 UVLS SDT that the design and characteristics of centrally controlled undervoltage-based load shedding are more appropriately categorized as RAS. The SPS SDT revised the definition of RAS to clarify that the definition is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. The SDT is coordinating this change with the Project 2008-02 UVLS SDT. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as a RAS. As a result, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective date of the revised definition of RAS.

## Attachment A – SDT Members

| Project 2010-05.2 – Special Protection Systems SDT |                                   |                                       |
|--|-----------------------------------|---------------------------------------|
|  | Participant                       | Entity                                |
| Chair  | Gene Henneberg                    | NV Energy / Berkshire Hathaway Energy |
| Vice Chair   | Bobby Jones                       | Southern Company                      |
| Member   | Amos Ang                          | Southern California Edison            |
|  | John Ciufo                        | Hydro One Inc.                        |
|  | Alan Engelmann                    | ComEd / Exelon                        |
|  | Davis Erwin                       | Pacific Gas and Electric              |
|  | Sharma Kolluri                    | Entergy                               |
|  | Charles-Eric Langlois             | Hydro-Quebec TransEnergie             |
|  | Robert J. O'Keefe                 | American Electric Power               |
|  | Hari Singh                        | Xcel Energy                           |
| NERC Staff   | Al McMeekin (Standards Developer) | NERC                                  |
|  | Phil Tatro (Technical Advisor)    | NERC                                  |
|  | Bill Edwards (Legal Counsel)      | NERC                                  |

# Project 2008-02 Undervoltage Load Shedding

Coordination Plan | June 11, 2014

## Background

Project 2008-02 Undervoltage Load Shedding (“UVLS Project”) proposes to consolidate and retire PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1 to create PRC-010-1 – Undervoltage Load Shedding. During development, the drafting team identified the following necessary corresponding changes to meet the design of PRC-010-1:

- 1) Retire three requirements in EOP-003-2 – Load Shedding Plans whose required performance is reflected in proposed PRC-010-1.
- 2) Revise the NERC Glossary definition of the term Special Protection System (SPS) to clarify that centrally controlled undervoltage-based load shedding is an SPS because of its design and characteristics.
- 3) Modify PRC-004-3 – Protection System Misoperation Identification and Correction, which excludes UVLS, to include certain types of UVLS programs as part of its applicable facilities.

To make these changes, the UVLS drafting team is coordinating with drafting teams from the three active NERC standard development projects listed below:

- Project 2009-03 – Emergency Operations (“EOP Project”)
- Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) (“SPS Project”)
- Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems) (“Misoperations Project”)



### **Current Coordination Plan**

NERC has developed a preferred coordination plan for the above-mentioned projects that will properly align the development and implementation of the revised standards and definitions with the retirements of the legacy standards.

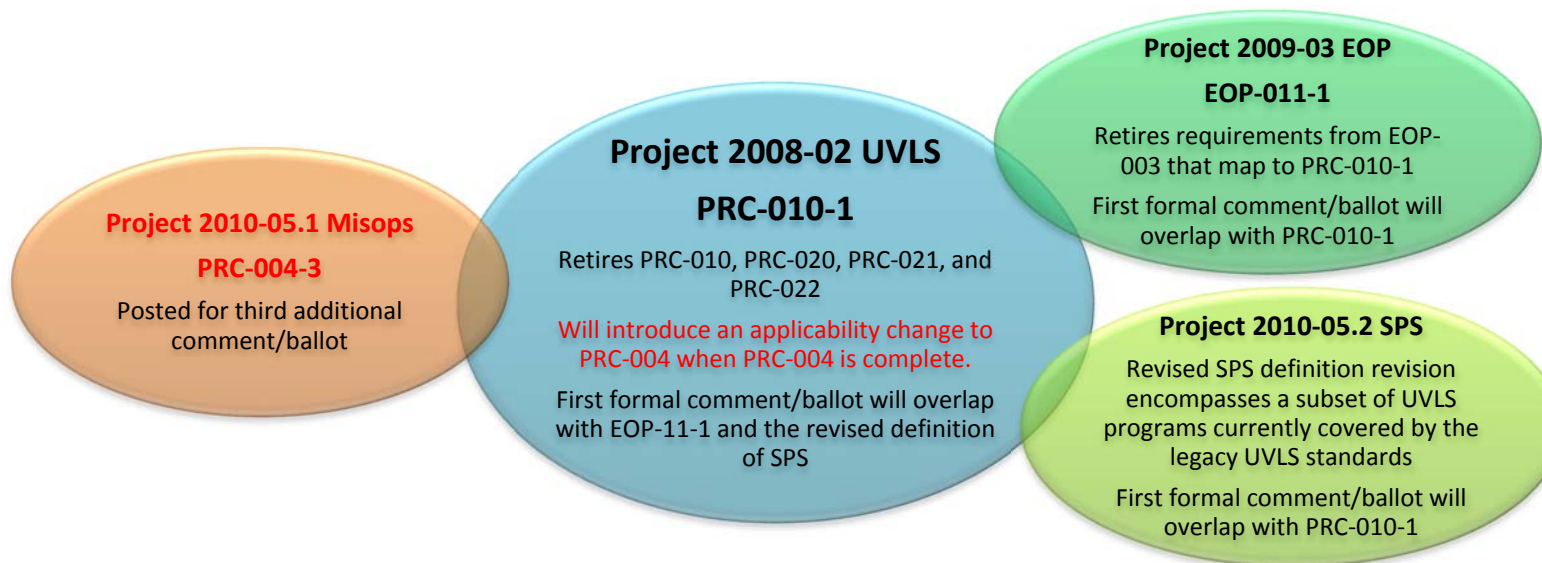
- 1) The EOP and UVLS Projects will progress simultaneously and coordinate necessary changes. Comment periods and ballots for each project will run concurrently or overlap.
- 2) The UVLS Project will progress simultaneously with the SPS definition revision by the SPS Project to assure the cohesive transfer of certain aspects of the legacy UVLS standards to the SPS standards. Comment periods and ballots for each project will run concurrently or overlap.
- 3) The UVLS Project will address the conforming changes needed to PRC-004 after PRC-004-3 is complete. How and when this will occur depends on when PRC-004-3 obtains approval from the ballot body and is adopted by the NERC Board of Trustees.

An illustrative diagram of this coordination appears on the next page. This plan is subject to change as necessary.

### **General Considerations**

The revised definition of SPS, the UVLS Project, and the EOP Project should be presented simultaneously to industry, the NERC Board of Trustees, and applicable regulatory authorities. The associated effective dates and retirements for these projects need to align to accommodate the needed transitions of standard coverage.

The implementation plan for the revised SPS definition will provide entities time to address any newly-identified SPS resulting from the application of the revised definition of SPS which will include centrally controlled undervoltage-based load shedding.



**April 2014**  
First SPS SDT Meeting

**February 2015**  
UVLS and EOP Standards and SPS Definition to BOT

**TBD**  
Revised SPS Standards to BOT

**June 2014**  
UVLS and EOP Standards and SPS Definition First Ballot

**April 2015**  
UVLS and EOP Standards and SPS Definition Petition Package to FERC

# Standards Announcement **Reminder**

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Remedial Action Scheme

**Additional Ballot Now Open through October 14, 2014**

### [Now Available](#)

An additional ballot for the **Revised Definition of Remedial Action Scheme** is open through **8 p.m. Eastern on Tuesday, October 14, 2014**.

### **Instructions for Balloting**

Members of the ballot pool associated with this project may log in and submit their vote for the definition by clicking [here](#).

**Note:** If a member cast a vote in the initial ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

### **Next Steps**

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition and post it for an additional ballot. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Wendy Muller](#),  
Standards Development Administrator, or at 404-446-2560.*

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## Standards Announcement

### Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Remedial Action Scheme

Formal Comment Period Now Open through October 14, 2014

#### [Now Available](#)

A 45-day formal comment period for the **Revised Definition of Remedial Action Scheme** is open through **8 p.m. Eastern on Tuesday, October 14, 2014.**

#### Instructions for Commenting

Please use the [electronic form](#) to submit comments on the revised definition. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

#### Next Steps

An additional ballot for the definition will be conducted **October 3-14, 2014.**

For information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Wendy Muller](#),  
Standards Development Administrator, or at 404-446-2560.*

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## Standards Announcement

### Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Remedial Action Scheme

Formal Comment Period Now Open through October 14, 2014

#### [Now Available](#)

A 45-day formal comment period for the **Revised Definition of Remedial Action Scheme** is open through **8 p.m. Eastern on Tuesday, October 14, 2014.**

#### Instructions for Commenting

Please use the [electronic form](#) to submit comments on the revised definition. If you experience any difficulties in using the electronic form, please contact [Wendy Muller](#). An off-line, unofficial copy of the comment form is posted on the [project page](#).

#### Next Steps

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# Standards Announcement

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Remedial Action Scheme

### Additional Ballot Results

#### [Now Available](#)

An additional ballot for the **Revised Definition of Remedial Action Scheme** concluded at **8 p.m. Eastern on Tuesday, October 14, 2014.**

The revised definition achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

| Ballot           |
|------------------|
| Quorum /Approval |
| 80.54% / 75.79%  |

Background information for this project can be found on the [project page](#).

### Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition and post it for an additional ballot. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Al McMeekin](#).*

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| Ballot Results                |  |
|-------------------------------|--|
| <b>Ballot Name:</b>           | Definition_of_Remedial_Action_Scheme       |
| <b>Ballot Period:</b>         | 10/3/2014 - 10/14/2014                     |
| <b>Ballot Type:</b>           | Additional                                 |
| <b>Total # Votes:</b>         | 298  |
| <b>Total Ballot Pool:</b>     | 370  |
| <b>Quorum:</b>                | <b>80.54 % The Quorum has been reached</b> |
| <b>Weighted Segment Vote:</b> | 75.79 %                                    |
| <b>Ballot Results:</b>        | <b>The Ballot has Closed</b>               |

| Summary of Ballot Results |             |                |             |          |          |          |                                 |         |         |  |
|---------------------------|-------------|----------------|-------------|----------|----------|----------|---------------------------------|---------|---------|--|
| Segment                   | Ballot Pool | Segment Weight | Affirmative |          | Negative |          | Negative Vote without a Comment | Abstain | No Vote |  |
|                           |             |                | # Votes     | Fraction | # Votes  | Fraction |                                 |         |         |  |
| 1 - Segment 1             | 101         | 1              | 52          | 0.667    | 26       | 0.333    | 0                               | 5       | 18      |  |
| 2 - Segment 2             | 9           | 0.6            | 5           | 0.5      | 1        | 0.1      | 1                               | 0       | 2       |  |
| 3 - Segment 3             | 84          | 1              | 45          | 0.714    | 18       | 0.286    | 0                               | 8       | 13      |  |
| 4 - Segment 4             | 27          | 1              | 14          | 0.875    | 2        | 0.125    | 0                               | 2       | 9       |  |
| 5 - Segment 5             | 79          | 1              | 38          | 0.717    | 15       | 0.283    | 0                               | 10      | 16      |  |
| 6 - Segment 6             | 53          | 1              | 28          | 0.757    | 9        | 0.243    | 0                               | 6       | 10      |  |
| 7 - Segment 7             | 3           | 0.1            | 1           | 0.1      | 0        | 0        | 0                               | 0       | 2       |  |
| 8 - Segment 8             | 4           | 0.3            | 2           | 0.2      | 1        | 0.1      | 0                               | 0       | 1       |  |
| 9 - Segment 9             | 3           | 0.2            | 1           | 0.1      | 1        | 0.1      | 0                               | 0       | 1       |  |

|                 |            |            |            |             |           |             |          |           |           |
|-----------------|------------|------------|------------|-------------|-----------|-------------|----------|-----------|-----------|
| 10 - Segment 10 | 7          | 0.7        | 6          | 0.6         | 1         | 0.1         | 0        | 0         | 0         |
| <b>Totals</b>   | <b>370</b> | <b>6.9</b> | <b>192</b> | <b>5.23</b> | <b>74</b> | <b>1.67</b> | <b>1</b> | <b>31</b> | <b>72</b> |

| Individual Ballot Pool Results |  |                              |             |  |
|--------------------------------|--|------------------------------|-------------|--|
| Segment                        | Organization                                     | Member                       | Ballot      | NERC Notes   |
| 1                              | Ameren Services                                  | Eric Scott                   | Affirmative |  |
| 1                              | American Electric Power                          | Paul B Johnson               | Affirmative |  |
| 1                              | American Transmission Company, LLC               | Andrew Z Puszta              | Affirmative |  |
| 1                              | Arizona Public Service Co.                       | Brian Cole                   | Affirmative |  |
| 1                              | Associated Electric Cooperative, Inc.            | John Bussman                 | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                       |
| 1                              | Austin Energy                                    | James Armke                  | Affirmative |  |
| 1                              | Avista Utilities                                 | Heather Rosentrater          | Affirmative |  |
| 1                              | Balancing Authority of Northern California       | Kevin Smith                  | Affirmative |  |
| 1                              | Baltimore Gas & Electric Company                 | Christopher J Scanlon        | Affirmative |  |
| 1                              | Basin Electric Power Cooperative                 | David Rudolph                |             |  |
| 1                              | BC Hydro and Power Authority                     | Patricia Robertson           | Affirmative |  |
| 1                              | Black Hills Corp                                 | Wes Wingen                   |             |  |
| 1                              | Bonneville Power Administration                  | Donald S. Watkins            | Affirmative |  |
| 1                              | Bryan Texas Utilities                            | John C Fontenot              | Affirmative |  |
| 1                              | CenterPoint Energy Houston Electric, LLC         | John Brockhan                | Affirmative |  |
| 1                              | Central Electric Power Cooperative               | Michael B Bax                | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                       |
| 1                              | Central Iowa Power Cooperative                   | Kevin J Lyons                | Negative    | SUPPORTS THIRD PARTY COMMENTS - (ACES)                       |
| 1                              | City of Tallahassee                              | Daniel S Langston            | Negative    | COMMENT RECEIVED   |
| 1                              | Clark Public Utilities                           | Jack Stamper                 | Affirmative |  |
| 1                              | Colorado Springs Utilities                       | Shawna Speer                 | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities) |
| 1                              | Consolidated Edison Co. of New York              | Christopher L de Graffenried | Negative    | COMMENT RECEIVED   |
| 1                              | Dairyland Power Coop.                            | Robert W. Roddy              | Affirmative |  |
| 1                              | Dayton Power & Light Co.                         | Hertzel Shamash              | Affirmative |  |
| 1                              | Deseret Power                                    | James Tucker                 |             |  |
| 1                              | Dominion Virginia Power                          | Larry Nash                   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Dominion)                   |
| 1                              | Duke Energy Carolina                             | Doug E Hils                  | Affirmative |  |
| 1                              | Entergy Transmission                             | Oliver A Burke               | Affirmative |  |
| 1                              | FirstEnergy Corp.                                | William J Smith              | Affirmative |  |
| 1                              | Florida Keys Electric Cooperative Assoc.         | Dennis Minton                | Affirmative |  |
| 1                              | Florida Power & Light Co.                        | Mike O'Neil                  | Affirmative |  |
| 1                              | Gainesville Regional Utilities                   | Richard Bachmeier            |             |  |
| 1                              | Georgia Transmission Corporation                 | Jason Snodgrass              | Affirmative |  |
| 1                              | Great River Energy                               | Gordon Pietsch               |             |  |
| 1                              | Hydro One Networks, Inc.                         | Muhammed Ali                 | Affirmative |  |
| 1                              | Hydro-Quebec TransEnergie                        | Martin Boisvert              | Affirmative |  |
| 1                              | Idaho Power Company                              | Molly Devine                 | Affirmative |  |
| 1                              | International Transmission Company Holdings Corp | Michael Moltane              | Negative    | COMMENT RECEIVED   |
| 1                              | JDRJC Associates                                 | Jim D Cyrulewski             | Abstain     |  |
| 1                              | JEA  | Ted E Hobson                 | Affirmative |  |
|                                |  |                              |             | SUPPORTS THIRD PARTY   |



|   |  |                         |             |   |
|---|--|-------------------------|-------------|---|
| 1 | KAMO Electric Cooperative                        | Walter Kenyon           | Negative    | COMMENTS - (AECI)   |
| 1 | Kansas City Power & Light Co.                    | Daniel Gibson           | Affirmative |   |
| 1 | Lakeland Electric                                | Larry E Watt            |             |   |
| 1 | Lincoln Electric System                          | Doug Bantam             |             |   |
| 1 | Long Island Power Authority                      | Robert Ganley           | Affirmative |   |
| 1 | Lower Colorado River Authority                   | Martyn Turner           | Affirmative |   |
| 1 | M & A Electric Power Cooperative                 | William Price           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                    |
| 1 | Manitoba Hydro                                   | Jo-Anne M Ross          | Affirmative |   |
| 1 | MEAG Power                                       | Danny Dees              | Affirmative |   |
| 1 | MidAmerican Energy Co.                           | Terry Harbour           | Negative    | COMMENT RECEIVED  |
| 1 | Minnkota Power Coop. Inc.                        | Daniel L Inman          |             |   |
| 1 | Muscatine Power & Water                          | Andrew J Kurriger       | Abstain     |   |
| 1 | N.W. Electric Power Cooperative, Inc.            | Mark Ramsey             | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                    |
| 1 | National Grid USA                                | Michael Jones           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's Comments.) |
| 1 | NB Power Corporation                             | Alan MacNaughton        |             |   |
| 1 | Nebraska Public Power District                   | Jamison Cawley          | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Support MRO NSRF Comments)               |
| 1 | New York Power Authority                         | Bruce Metruck           | Affirmative |   |
| 1 | Northeast Missouri Electric Power Cooperative    | Kevin White             | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                                    |
| 1 | Northeast Utilities                              | William Temple          | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NPCC)                                    |
| 1 | Northern Indiana Public Service Co.              | Julaine Dyke            | Abstain     |   |
| 1 | Ohio Valley Electric Corp.                       | Scott R Cunningham      | Affirmative |   |
| 1 | Oklahoma Gas and Electric Co.                    | Terri Pyle              | Affirmative |   |
| 1 | Omaha Public Power District                      | Doug Peterchuck         | Affirmative |   |
| 1 | Oncor Electric Delivery                          | Jen Fiegel              | Affirmative |   |
| 1 | Orlando Utilities Commission                     | Brad Chase              |             |   |
| 1 | Otter Tail Power Company                         | Daryl Hanson            |             |   |
| 1 | Pacific Gas and Electric Company                 | Bangalore Vijayraghavan |             |   |
| 1 | Peak Reliability                                 | Jared Shakespeare       | Affirmative |   |
| 1 | Platte River Power Authority                     | John C. Collins         | Affirmative |   |
| 1 | Portland General Electric Co.                    | John T Walker           |             |   |
| 1 | Potomac Electric Power Co.                       | David Thorne            | Affirmative |   |
| 1 | PPL Electric Utilities Corp.                     | Brenda L Truhe          | Abstain     |   |
| 1 | Public Service Company of New Mexico             | Laurie Williams         | Affirmative |   |
| 1 | Public Service Electric and Gas Co.              | Kenneth D. Brown        | Affirmative |   |
| 1 | Public Utility District No. 1 of Okanogan County | Dale Dunckel            |             |   |
| 1 | Puget Sound Energy, Inc.                         | Denise M Lietz          | Affirmative |   |
| 1 | Rochester Gas and Electric Corp.                 | John C. Allen           | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NPCC)                                    |
| 1 | Sacramento Municipal Utility District            | Tim Kelley              | Affirmative |   |
| 1 | Salt River Project                               | Robert Kondziolka       | Affirmative |   |
| 1 | San Diego Gas & Electric                         | Will Speer              |             |   |
| 1 | SaskPower  | Wayne Guttormson        | Abstain     |   |
| 1 | Seattle City Light                               | Pawel Krupa             | Affirmative |   |
| 1 | Seminole Electric Cooperative, Inc.              | Glenn Spurlock          | Affirmative |   |

|   |  |                                  |             |   |
|---|--|----------------------------------|-------------|---|
| 1 | Sho-Me Power Electric Cooperative                        | Denise Stevens                   | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(AECI)     |
| 1 | Snohomish County PUD No. 1                               | Long T Duong                     | Affirmative |   |
| 1 | South Carolina Electric & Gas Co.                        | Tom Hanzlik                      | Affirmative |   |
| 1 | South Carolina Public Service Authority                  | Shawn T Abrams                   | Negative    | COMMENT<br>RECEIVED                                 |
| 1 | Southern California Edison Company                       | Steven Mavis                     | Affirmative |   |
| 1 | Southern Company Services, Inc.                          | Robert A. Schaffeld              | Affirmative |   |
| 1 | Southern Illinois Power Coop.                            | William Hutchison                | Affirmative |   |
| 1 | Southwest Transmission Cooperative, Inc.                 | John Shaver                      | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(ACES)     |
| 1 | Sunflower Electric Power Corporation                     | Noman Lee Williams               | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(ACES)     |
| 1 | Tacoma Power   | John Merrell                     | Negative    | COMMENT<br>RECEIVED                                 |
| 1 | Tennessee Valley Authority                               | Howell D Scott                   | Negative    | COMMENT<br>RECEIVED                                 |
| 1 | Tri-State Generation & Transmission<br>Association, Inc. | Tracy Sliaman                    | Negative    | COMMENT<br>RECEIVED                                 |
| 1 | Tucson Electric Power Co.                                | John Tolo                        | Affirmative |   |
| 1 | U.S. Bureau of Reclamation                               | Richard T Jackson                |             |   |
| 1 | United Illuminating Co.                                  | Jonathan Appelbaum               | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(NPCC)     |
| 1 | Westar Energy  | Allen Klassen                    |             |   |
| 1 | Western Area Power Administration                        | Lloyd A Linke                    | Negative    | COMMENT<br>RECEIVED                                 |
| 1 | Wolverine Power Supply Coop., Inc.                       | Michelle Clements                |             |   |
| 1 | Xcel Energy, Inc.  | Gregory L Pieper                 | Affirmative |   |
| 2 | BC Hydro   | Venkataramakrishnan<br>Vinnakota | Negative    | NO COMMENT<br>RECEIVED -<br>(Patricia<br>Robertson) |
| 2 | California ISO   | Rich Vine                        | Affirmative |   |
| 2 | Electric Reliability Council of Texas, Inc.              | Cheryl Moseley                   | Affirmative |   |
| 2 | Independent Electricity System Operator                  | Leonard Kula                     | Affirmative |   |
| 2 | ISO New England, Inc.                                    | Matthew F Goldberg               | Negative    | COMMENT<br>RECEIVED                                 |
| 2 | MISO   | Marie Knox                       |             |   |
| 2 | New York Independent System Operator                     | Gregory Campoli                  |             |   |
| 2 | PJM Interconnection, L.L.C.                              | stephanie monzon                 | Affirmative |   |
| 2 | Southwest Power Pool, Inc.                               | Charles H. Yeung                 | Affirmative |   |
| 3 | AEP  | Michael E Deloach                | Affirmative |   |
| 3 | Alabama Power Company                                    | Robert S Moore                   | Affirmative |   |
| 3 | Ameren Corp.   | David J Jendras                  | Affirmative |   |
| 3 | APS  | Sarah Kist                       | Affirmative |   |
| 3 | Associated Electric Cooperative, Inc.                    | Todd Bennett                     | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(AECI)     |
| 3 | Atlantic City Electric Company                           | NICOLE BUCKMAN                   | Affirmative |   |
| 3 | Avista Corp.   | Scott J Kinney                   | Affirmative |   |
| 3 | BC Hydro and Power Authority                             | Pat G. Harrington                | Affirmative |   |
| 3 | Bonneville Power Administration                          | Rebecca Berdahl                  | Affirmative |   |
| 3 | Central Electric Power Cooperative                       | Adam M Weber                     | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(AECI)     |
| 3 | Central Lincoln PUD                                      | Steve Alexanderson               | Affirmative |   |
| 3 | City of Austin dba Austin Energy                         | Andrew Gallo                     | Affirmative |   |
| 3 | City of Clewiston  | Lynne Mila                       | Affirmative |   |
| 3 | City of Farmington                                       | Linda R Jacobson                 | Abstain     |   |
| 3 | City of Garland  | Ronnie C Hoeninghaus             | Abstain     |   |
| 3 | City of Green Cove Springs                               | Mark Schultz                     | Affirmative |   |
| 3 | City of Redding  | Bill Hughes                      | Affirmative |   |

|   |   |                     |             |   |
|---|---|---------------------|-------------|---|
| 3 | City of Tallahassee                     | Bill R Fowler       | Negative    | COMMENT RECEIVED  |
| 3 | City of Vineland                        | Kathy Caignon       |             |   |
| 3 | Cleco Corporation                       | Michelle A Corley   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (See previous SPP comments)       |
| 3 | Colorado Springs Utilities              | Jean Mueller        | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Kaleb Brimhall, CSU)             |
| 3 | ComEd                                   | John Bee            | Affirmative |   |
| 3 | Consolidated Edison Co. of New York     | Peter T Yost        | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NPCC)                            |
| 3 | Consumers Energy Company                | Gerald G Farringer  | Affirmative |   |
| 3 | Cowlitz County PUD                      | Russell A Noble     | Affirmative |   |
| 3 | CPS Energy                              | Jose Escamilla      |             |   |
| 3 | Delmarva Power & Light Co.              | Michael R. Mayer    | Affirmative |   |
| 3 | Dominion Resources, Inc.                | Connie B Lowe       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Dominion's)                      |
| 3 | DTE Electric                            | Kent Kujala         | Abstain     |   |
| 3 | FirstEnergy Corp.                       | Cindy E Stewart     | Affirmative |   |
| 3 | Florida Keys Electric Cooperative       | Tom B Anthony       | Affirmative |   |
| 3 | Florida Municipal Power Agency          | Joe McKinney        | Affirmative |   |
| 3 | Florida Power Corporation               | Lee Schuster        | Affirmative |   |
| 3 | Gainesville Regional Utilities          | Kenneth Simmons     | Affirmative |   |
| 3 | Great River Energy                      | Brian Glover        |             |   |
| 3 | Hydro One Networks, Inc.                | Ayesha Sabouba      | Affirmative |   |
| 3 | Imperial Irrigation District            | Jesus S. Alcaraz    |             |   |
| 3 | JEA                                     | Garry Baker         |             |   |
| 3 | KAMO Electric Cooperative               | Theodore J Hilmes   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative) |
| 3 | Kansas City Power & Light Co.           | Joshua D Bach       | Affirmative |   |
| 3 | Kissimmee Utility Authority             | Gregory D Woessner  |             |   |
| 3 | Lakeland Electric                       | Mace D Hunter       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (FMPA)                            |
| 3 | Lincoln Electric System                 | Jason Fortik        | Abstain     |   |
| 3 | Los Angeles Department of Water & Power | Mike Anctil         |             |   |
| 3 | Louisville Gas and Electric Co.         | Charles A. Freibert | Abstain     |   |
| 3 | M & A Electric Power Cooperative        | Stephen D Pogue     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                            |
| 3 | Manitoba Hydro                          | Greg C. Parent      | Affirmative |   |
| 3 | MEAG Power                              | Roger Brand         | Affirmative |   |
| 3 | MidAmerican Energy Co.                  | Thomas C. Mielnik   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF Comments)               |
| 3 | Modesto Irrigation District             | Jack W Savage       | Affirmative |   |
| 3 | National Grid USA                       | Brian E Shanahan    | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NPCC)                            |
| 3 | Nebraska Public Power District          | Tony Eddleman       | Negative    | SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF comments.)              |
| 3 | New York Power Authority                | David R Rivera      | Affirmative |   |
| 3 | Northeast Missouri Electric Power       | Skylar Wiegmann     |             |   |

|   |   |                     |             |  |
|---|---|---------------------|-------------|--|
|   | Cooperative   |                     |             |  |
| 3 | Northern Indiana Public Service Co.                   | Ramon J Barany      | Abstain     |  |
| 3 | NW Electric Power Cooperative, Inc.                   | David McDowell      |             |  |
| 3 | Ocala Utility Services                                | Randy Hahn          | Affirmative |  |
| 3 | Oklahoma Gas and Electric Co.                         | Donald Hargrove     | Affirmative |  |
| 3 | Omaha Public Power District                           | Blaine R. Dinwiddie |             |  |
| 3 | Orlando Utilities Commission                          | Ballard K Mutters   | Affirmative |  |
| 3 | Owensboro Municipal Utilities                         | Thomas T Lyons      | Abstain     |  |
| 3 | Pacific Gas and Electric Company                      | John H Hagen        | Affirmative |  |
| 3 | Platte River Power Authority                          | Terry L Baker       | Affirmative |  |
| 3 | PNM Resources   | Michael Mertz       |             |  |
| 3 | Portland General Electric Co.                         | Thomas G Ward       | Abstain     |  |
| 3 | Potomac Electric Power Co.                            | Mark Yerger         | Affirmative |  |
| 3 | Public Service Electric and Gas Co.                   | Jeffrey Mueller     | Affirmative |  |
| 3 | Puget Sound Energy, Inc.                              | Mariah R Kennedy    | Affirmative |  |
| 3 | Sacramento Municipal Utility District                 | James Leigh-Kendall | Affirmative |  |
| 3 | Salt River Project                                    | John T. Underhill   | Affirmative |  |
| 3 | Santee Cooper   | James M Poston      | Negative    | COMMENT RECEIVED                                 |
| 3 | Seattle City Light                                    | Dana Wheelock       | Affirmative |  |
| 3 | Seminole Electric Cooperative, Inc.                   | James R Frauen      | Affirmative |  |
| 3 | Sho-Me Power Electric Cooperative                     | Jeff L Neas         |             |  |
| 3 | Snohomish County PUD No. 1                            | Mark Oens           | Affirmative |  |
| 3 | South Carolina Electric & Gas Co.                     | Hubert C Young      | Affirmative |  |
| 3 | Southern California Edison Company                    | Lujuanna Medina     | Affirmative |  |
| 3 | Tacoma Power  | Marc Donaldson      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (John Merrell)   |
| 3 | Tampa Electric Co.                                    | Ronald L. Donahey   |             |  |
| 3 | Tennessee Valley Authority                            | Ian S Grant         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (TVA)            |
| 3 | Tri-State Generation & Transmission Association, Inc. | Janelle Marriott    | Negative    | COMMENT RECEIVED                                 |
| 3 | Westar Energy   | Bo Jones            | Affirmative |  |
| 3 | Wisconsin Electric Power Marketing                    | James R Keller      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski) |
| 3 | Xcel Energy, Inc.                                     | Michael Ibold       | Affirmative |  |
| 4 | Alliant Energy Corp. Services, Inc.                   | Kenneth Goldsmith   | Affirmative |  |
| 4 | Blue Ridge Power Agency                               | Duane S Dahlquist   | Abstain     |  |
| 4 | Central Lincoln PUD                                   | Shamus J Gamache    |             |  |
| 4 | City of Austin dba Austin Energy                      | Reza Ebrahimian     | Affirmative |  |
| 4 | City of Redding                                       | Nicholas Zettel     | Affirmative |  |
| 4 | City Utilities of Springfield, Missouri               | John Allen          |             |  |
| 4 | Constellation Energy Control & Dispatch, L.L.C.       | Margaret Powell     |             |  |
| 4 | Consumers Energy Company                              | Tracy Goble         |             |  |
| 4 | Cowlitz County PUD                                    | Rick Syring         | Affirmative |  |
| 4 | DTE Electric  | Daniel Herring      | Abstain     |  |
| 4 | Florida Municipal Power Agency                        | Carol Chinn         | Affirmative |  |
| 4 | Georgia System Operations Corporation                 | Guy Andrews         |             |  |
| 4 | Herb Schrayshuen                                      | Herb Schrayshuen    | Affirmative |  |
| 4 | Illinois Municipal Electric Agency                    | Bob C. Thomas       | Affirmative |  |
| 4 | Indiana Municipal Power Agency                        | Jack Alvey          |             |  |
| 4 | Integrus Energy Group, Inc.                           | Christopher Plante  |             |  |
| 4 | Madison Gas and Electric Co.                          | Joseph DePoorter    | Affirmative |  |
| 4 | Modesto Irrigation District                           | Spencer Tacke       | Affirmative |  |
| 4 | Ohio Edison Company                                   | Douglas Hohlbaugh   | Affirmative |  |
| 4 | Public Utility District No. 1 of Snohomish County     | John D Martinsen    | Affirmative |  |
| 4 | Sacramento Municipal Utility District                 | Mike Ramirez        | Affirmative |  |
| 4 | Seattle City Light                                    | Hao Li              | Affirmative |  |
| 4 | Seminole Electric Cooperative, Inc.                   | Steven R Wallace    | Affirmative |  |
| 4 | South Mississippi Electric Power Association          | Steve McElhaney     |             |  |
|   |   |                     |             | SUPPORTS   |

|   |   |                     |             |  |
|---|---|---------------------|-------------|--|
| 4 | Tacoma Public Utilities   | Keith Morisette     | Negative    | THIRD PARTY COMMENTS - (John Merrell)                        |
| 4 | Utility Services, Inc.  | Brian Evans-Mongeon | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NPCC)                       |
| 4 | Wisconsin Energy Corp.  | Anthony P Jankowski |             |  |
| 5 | Amerenue  | Sam Dwyer           | Affirmative |  |
| 5 | American Electric Power   | Thomas Foltz        | Affirmative |  |
| 5 | Arizona Public Service Co.  | Scott Takinen       | Affirmative |  |
| 5 | Associated Electric Cooperative, Inc.                             | Matthew Pacobit     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)                       |
| 5 | BC Hydro and Power Authority                                      | Clement Ma          | Affirmative |  |
| 5 | Boise-Kuna Irrigation District/dba Lucky peak power plant project | Mike D Kukla        | Affirmative |  |
| 5 | Bonneville Power Administration                                   | Francis J. Halpin   | Affirmative |  |
| 5 | Brazos Electric Power Cooperative, Inc.                           | Shari Heino         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (ACES)                       |
| 5 | Calpine Corporation   | Hamid Zakery        | Negative    | COMMENT RECEIVED   |
| 5 | City of Austin dba Austin Energy                                  | Jeanie Doty         | Affirmative |  |
| 5 | City of Redding   | Paul A. Cummings    | Affirmative |  |
| 5 | City of Tallahassee   | Karen Webb          | Negative    | COMMENT RECEIVED   |
| 5 | Cleco Power   | Stephanie Huffman   | Negative    | SUPPORTS THIRD PARTY COMMENTS - (See previous SPP comments)  |
| 5 | Colorado Springs Utilities  | Kaleb Brimhall      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities) |
| 5 | Con Edison Company of New York                                    | Brian O'Boyle       | Negative    | COMMENT RECEIVED   |
| 5 | Consumers Energy Company  | David C Greyerbiehl | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Richard Pienkos)            |
| 5 | Cowlitz County PUD  | Bob Essex           | Affirmative |  |
| 5 | Dairyland Power Coop.   | Tommy Drea          |             |  |
| 5 | Dominion Resources, Inc.  | Mike Garton         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Dominion)                   |
| 5 | DTE Electric  | Mark Stefaniak      | Abstain     |  |
| 5 | Duke Energy   | Dale Q Goodwine     | Affirmative |  |
| 5 | Dynegy Inc.   | Dan Roethemeyer     | Affirmative |  |
| 5 | E.ON Climate & Renewables North America, LLC                      | Dana Showalter      |             |  |
| 5 | Entergy Services, Inc.  | Tracey Stubbs       | Abstain     |  |
| 5 | Exelon Nuclear  | Mark F Draper       | Affirmative |  |
| 5 | First Wind  | John Robertson      |             |  |
| 5 | FirstEnergy Solutions   | Kenneth Dresner     | Affirmative |  |
| 5 | Florida Municipal Power Agency                                    | David Schumann      | Affirmative |  |
| 5 | Great River Energy  | Preston L Walsh     |             |  |
| 5 | Hydro-Québec Production   | Roger Dufresne      | Abstain     |  |
| 5 | Independence Power & Light Dept.                                  | James Nail          | Affirmative |  |
| 5 | Ingleside Cogeneration LP   | Michelle R DAntuono | Affirmative |  |
| 5 | JEA   | John J Babik        | Affirmative |  |
| 5 | Kansas City Power & Light Co.                                     | Brett Holland       | Affirmative |  |
| 5 | Kissimmee Utility Authority                                       | Mike Blough         | Affirmative |  |
| 5 | Lakeland Electric   | James M Howard      |             |  |
| 5 | Liberty Electric Power LLC  | Daniel Duff         | Affirmative |  |
| 5 | Lincoln Electric System   | Dennis Florom       | Abstain     |  |

|   |   |                    |             |  |
|---|---|--------------------|-------------|--|
| 5 | Los Angeles Department of Water & Power                   | Kenneth Silver     |             |  |
| 5 | Lower Colorado River Authority                            | Dixie Wells        | Affirmative |  |
| 5 | Luminant Generation Company LLC                           | Rick Terrill       |             |  |
| 5 | Manitoba Hydro  | Chris Mazur        | Affirmative |  |
| 5 | Massachusetts Municipal Wholesale Electric Company        | David Gordon       | Abstain     |  |
| 5 | MEAG Power  | Steven Grego       | Affirmative |  |
| 5 | Muscatine Power & Water                                   | Mike Avesing       | Abstain     |  |
| 5 | Nebraska Public Power District                            | Don Schmit         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)       |
| 5 | Nevada Power Co.  | Richard Salgo      | Affirmative |  |
| 5 | New York Power Authority                                  | Wayne Sipperly     | Affirmative |  |
| 5 | NextEra Energy  | Allen D Schriver   | Affirmative |  |
| 5 | Northern Indiana Public Service Co.                       | Michael D Melvin   | Abstain     |  |
| 5 | Oglethorpe Power Corporation                              | Bernard Johnson    | Affirmative |  |
| 5 | Oklahoma Gas and Electric Co.                             | Henry L Staples    | Affirmative |  |
| 5 | Omaha Public Power District                               | Mahmood Z. Safi    | Affirmative |  |
| 5 | Orlando Utilities Commission                              | Richard K Kinas    |             |  |
| 5 | Pacific Gas and Electric Company                          | Alex Chua          | Abstain     |  |
| 5 | Platte River Power Authority                              | Christopher R Wood | Affirmative |  |
| 5 | Portland General Electric Co.                             | Matt E. Jastram    |             |  |
| 5 | PPL Generation LLC  | Annette M Bannon   | Abstain     |  |
| 5 | PSEG Fossil LLC   | Tim Kucey          | Affirmative |  |
| 5 | Public Utility District No. 1 of Lewis County             | Steven Grega       |             |  |
| 5 | Public Utility District No. 2 of Grant County, Washington | Michiko Sell       |             |  |
| 5 | Puget Sound Energy, Inc.                                  | Lynda Kupfer       | Affirmative |  |
| 5 | Sacramento Municipal Utility District                     | Susan Gill-Zobitz  | Affirmative |  |
| 5 | Salt River Project  | William Alkema     |             |  |
| 5 | Santee Cooper   | Lewis P Pierce     | Negative    | COMMENT RECEIVED                                 |
| 5 | Seattle City Light  | Michael J. Haynes  |             |  |
| 5 | Seminole Electric Cooperative, Inc.                       | Brenda K. Atkins   | Affirmative |  |
| 5 | Snohomish County PUD No. 1                                | Sam Nietfeld       | Affirmative |  |
| 5 | South Carolina Electric & Gas Co.                         | Edward Magic       | Abstain     |  |
| 5 | Southern California Edison Company                        | Denise Yaffe       | Affirmative |  |
| 5 | Southern Company Generation                               | William D Shultz   | Affirmative |  |
| 5 | Tacoma Power  | Chris Mattson      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (John Merrell)   |
| 5 | Tennessee Valley Authority                                | David Thompson     | Negative    | COMMENT RECEIVED                                 |
| 5 | Tri-State Generation & Transmission Association, Inc.     | Mark Stein         | Negative    | COMMENT RECEIVED                                 |
| 5 | U.S. Army Corps of Engineers                              | Melissa Kurtz      |             |  |
| 5 | USDI Bureau of Reclamation                                | Erika Doot         |             |  |
| 5 | Westar Energy   | Bryan Taggart      |             |  |
| 5 | Wisconsin Electric Power Co.                              | Linda Horn         | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski) |
| 5 | Xcel Energy, Inc.   | Mark A Castagneri  | Affirmative |  |
| 6 | AEP Marketing   | Edward P. Cox      | Affirmative |  |
| 6 | Ameren Missouri   | Robert Quinlivan   | Affirmative |  |
| 6 | APS   | Randy A. Young     | Affirmative |  |
| 6 | Associated Electric Cooperative, Inc.                     | Brian Ackermann    | Negative    | SUPPORTS THIRD PARTY COMMENTS - (AECI)           |
| 6 | Bonneville Power Administration                           | Brenda S. Anderson | Affirmative |  |
| 6 | Calpine Energy Services                                   | Agus Bintoro       |             |  |
| 6 | City of Austin dba Austin Energy                          | Lisa Martin        | Affirmative |  |
| 6 | City of Redding   | Marvin Briggs      | Affirmative |  |
| 6 | Cleco Power LLC   | Robert Hirchak     | Negative    | SUPPORTS THIRD PARTY COMMENTS - (See previous    |

|   |  |                       |             | SPP comments)  |
|---|--|-----------------------|-------------|--|
| 6 | Colorado Springs Utilities                       | Shannon Fair          | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities) |
| 6 | Con Edison Company of New York                   | David Balban          | Negative    | COMMENT RECEIVED   |
| 6 | Constellation Energy Commodities Group           | David J Carlson       | Affirmative |  |
| 6 | Dominion Resources, Inc.                         | Louis S. Slade        | Negative    | SUPPORTS THIRD PARTY COMMENTS - (Dominion)                   |
| 6 | Duke Energy                                      | Greg Cecil            | Affirmative |  |
| 6 | FirstEnergy Solutions                            | Kevin Querry          | Affirmative |  |
| 6 | Florida Municipal Power Agency                   | Richard L. Montgomery | Affirmative |  |
| 6 | Florida Municipal Power Pool                     | Thomas Reedy          | Affirmative |  |
| 6 | Florida Power & Light Co.                        | Silvia P Mitchell     | Affirmative |  |
| 6 | Kansas City Power & Light Co.                    | Jessica L Klinghoffer | Affirmative |  |
| 6 | Lakeland Electric                                | Paul Shipps           |             |  |
| 6 | Lincoln Electric System                          | Eric Ruskamp          | Abstain     |  |
| 6 | Los Angeles Department of Water & Power          | Brad Packer           | Abstain     |  |
| 6 | Lower Colorado River Authority                   | Michael Shaw          | Affirmative |  |
| 6 | Luminant Energy                                  | Brenda Hampton        |             |  |
| 6 | Manitoba Hydro                                   | Blair Mukanik         | Affirmative |  |
| 6 | Modesto Irrigation District                      | James McFall          | Affirmative |  |
| 6 | Muscatine Power & Water                          | John Stolley          | Affirmative |  |
| 6 | New York Power Authority                         | Shivaz Chopra         | Affirmative |  |
| 6 | New York State Electric & Gas Corp.              | Julie S King          | Abstain     |  |
| 6 | Northern Indiana Public Service Co.              | Joseph O'Brien        | Abstain     |  |
| 6 | Oglethorpe Power Corporation                     | Donna Johnson         | Affirmative |  |
| 6 | Oklahoma Gas and Electric Co.                    | Jerry Nottngel        | Affirmative |  |
| 6 | Omaha Public Power District                      | Douglas Collins       |             |  |
| 6 | PacifiCorp                                       | Sandra L Shaffer      | Negative    | SUPPORTS THIRD PARTY COMMENTS - (MidAmerican)                |
| 6 | Platte River Power Authority                     | Carol Ballantine      |             |  |
| 6 | Portland General Electric Co.                    | Shawn P Davis         |             |  |
| 6 | Powerex Corp.                                    | Gordon Dobson-Mack    |             |  |
| 6 | PPL EnergyPlus LLC                               | Elizabeth Davis       | Abstain     |  |
| 6 | PSEG Energy Resources & Trade LLC                | Peter Dolan           | Affirmative |  |
| 6 | Public Utility District No. 1 of Chelan County   | Hugh A. Owen          | Abstain     |  |
| 6 | Sacramento Municipal Utility District            | Diane Enderby         | Affirmative |  |
| 6 | Salt River Project                               | William Abraham       | Affirmative |  |
| 6 | Santee Cooper                                    | Michael Brown         | Negative    | COMMENT RECEIVED   |
| 6 | Seattle City Light                               | Dennis Sismaet        | Affirmative |  |
| 6 | Seminole Electric Cooperative, Inc.              | Trudy S. Novak        | Affirmative |  |
| 6 | Snohomish County PUD No. 1                       | Kenn Backholm         | Affirmative |  |
| 6 | South Carolina Electric & Gas Co.                | Matt H Bullard        |             |  |
| 6 | Southern California Edison Company               | Joseph T Marone       | Affirmative |  |
| 6 | Southern Company Generation and Energy Marketing | John J. Ciza          | Affirmative |  |
| 6 | Tacoma Public Utilities                          | Michael C Hill        | Negative    | SUPPORTS THIRD PARTY COMMENTS - (John Merrell)               |
| 6 | Tampa Electric Co.                               | Benjamin F Smith II   |             |  |
| 6 | Tennessee Valley Authority                       | Marjorie S Parsons    | Negative    | COMMENT RECEIVED   |
| 6 | Westar Energy                                    | Grant L Wilkerson     |             |  |
| 7 | Luminant Mining Company LLC                      | Stewart Rake          |             |  |
| 7 | Occidental Chemical                              | Venona Greaff         | Affirmative |  |
| 7 | Siemens Energy, Inc.                             | Frank R. McElvain     |             |  |
| 8 |  | David L Kiguel        | Affirmative |  |
| 8 |  | Roger C Zaklukiewicz  | Negative    | SUPPORTS THIRD PARTY COMMENTS - (NPCC)                       |



|    |   |                     |             |   |
|----|---|---------------------|-------------|---|
| 8  | Massachusetts Attorney General                                  | Frederick R Plett   | Affirmative |   |
| 8  | Volkman Consulting, Inc.  | Terry Volkman       |             |   |
| 9  | Central Lincoln PUD   | Bruce Lovelin       | Affirmative |   |
| 9  | Commonwealth of Massachusetts<br>Department of Public Utilities | Donald Nelson       | Negative    | SUPPORTS<br>THIRD PARTY<br>COMMENTS -<br>(NPCC) |
| 9  | New York State Public Service Commission                        | Diane J Barney      |             |   |
| 10 | Midwest Reliability Organization                                | Russel Mountjoy     | Affirmative |   |
| 10 | New York State Reliability Council                              | Alan Adamson        | Affirmative |   |
| 10 | Northeast Power Coordinating Council                            | Guy V. Zito         | Negative    | COMMENT<br>RECEIVED                             |
| 10 | ReliabilityFirst  | Anthony E Jablonski | Affirmative |   |
| 10 | SERC Reliability Corporation                                    | Joseph W Spencer    | Affirmative |   |
| 10 | Texas Reliability Entity, Inc.                                  | Karin Schweitzer    | Affirmative |   |
| 10 | Western Electricity Coordinating Council                        | Steven L. Rueckert  | Affirmative |   |
|    |   |                     |             |   |

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**Individual or group. (45 Responses)**

**Name (29 Responses)**

**Organization (29 Responses)**

**Group Name (16 Responses)**

**Lead Contact (16 Responses)**

**IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)**

**Comments (45 Responses)**

**Question 1 (40 Responses)**

**Question 1 Comments (40 Responses)**

|   |
|---|
|   |
| Group   |
| Northeast Power Coordinating Council  |
| Guy Zito  |
|   |
| No  |
| In PRC-024-1(X), A. Introduction 5. Effective Date was removed, and replaced by the Effective Date paragraph. This change is not only not indicated in the redline, but more importantly it removed the "phased-in" implementation of PRC-024-1 which was necessitated by the requirements of the standard. Is the intent to remove the "phase-in" percentages by the single effective date indicated by the Effective Date paragraph in PRC-024-1(X)? Under A.5 Effective Date: of PRC-025-1(X) the words "See Implementation Plan" were deleted. PRC-025-1(X) has its own Implementation Plan which is part of the standard's "package". However, to ensure clarity and avoid misunderstanding, suggest leaving "See Implementation Plan" in A.5. The Implementation Plan must be revised to be consistent with the intended revisions. It should be made clear that all aspects of the Implementation Plans for PRC-024-1 and PRC-025-1 will remain applicable to those standards. In part (b) on page 1, what is meant by "distributed relays"? Are "distributed relays" intended to be distribution system relays? The wording needs clarification. Please add the following to "The following do not individually constitute a RAS:" list: The controllers at each terminal of a High Voltage direct current (HVdc) Facility that may or may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility. |
| Group   |
| Arizona Public Service Co   |
| Janet Smith   |
|   |
| Yes   |
|   |
| Individual  |

Thomas Foltz

American Electric Power

Yes

Within the section “The following do not individually constitute a RAS”, AEP recommends the following changes: Item a: Delete “BES” so that it reads “Protection Systems installed for the purpose of detecting Faults on Elements and isolating the faulted Elements”. Item e: Add the qualifier “reverse power” so that it reads “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, reverse power, or overload to protect the Element against damage by removing it from service.” Item k: Delete the phrase “that proceed when” and add the text “that proceeds directly to a desired system state” so that it reads “Automatic sequences manually initiated solely by a System Operator that proceeds directly to a desired system state.”

Individual

Barbara Kedrowski

Wisconsin Electric Power Co

No

We propose that the following changes be made to the list of exclusions: Item (e) – To “schemes applied to an Element for non-Fault conditions”, add the following: overexcitation, over/under- frequency, motoring, load rejection, and unbalanced system conditions. We believe these are abnormal, non-Fault system conditions for which protection is commonly applied, and should not be considered RAS. Item (n) Replace “Generator controls ...” with “Generator or turbine controls...” Add a new exclusion for protective functions for black start generators that may be implemented to allow greater than normal voltage or frequency tolerance during restoration conditions.

Individual

Amy Casuscelli

Xcel Energy

Yes

While Xcel Energy agrees with the revised definition, we offer the comments below for the Drafting Team's consideration: We observe that the proposed new RAS definition is substantively and structurally very similar to the existing SPS/RAS definition. The most significant change in the proposed new definition is the detailed list of 14 exclusions versus the 3 exclusions in the existing definition – we agree that the additional exclusions are a useful enhancement. However, the functional description of RAS characterized by its purpose and actions is almost the same in both definitions – we note that the first sentence in both definitions contains identical verbiage “designed to detect predetermined System conditions and (automatically) take corrective actions...”. In the new definition, this is followed by a

listing of typical corrective actions before stating the reliability objectives in the second sentence – whereas the existing definition enumerates them both in the second sentence. However, the three examples provided for corrective actions and objectives are common to both definitions, and are supplemented with two additional reliability objectives in the proposed new definition. Given these substantive commonalities, we recommend that the proposed new definition be restructured as follows to make it easier to discern the similarities retained and the enhancements introduced relative to the existing definition, as well as improve its contextual clarity and readability. [A scheme designed to detect predetermined System conditions and automatically take corrective actions <to> accomplish <BES reliability> objectives such as: (1) Meet requirements identified in the NERC Reliability Standards (2) Maintain Bulk Electric System (BES) stability (3) Maintain acceptable BES voltages (4) Maintain acceptable BES power flows(5) Limit the impact of Cascading or extreme events. Corrective actions may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring System(s).] Irrespective of whether the proposed restructuring of the definition is implemented or not, we suggest that the reliability objectives be re-sequenced. Due to the non-specific “catch-all” nature of the first objective (meet requirements in reliability standards), we recommend that it be listed as the last objective to follow the four specific attributes of reliable system performance.

Group

Colorado Springs Utilities

Kaleb Brimhall

No

1. The last bullet of the definition, before all the exclusions, says “Limit the impact of Cascading or extreme events. We recommend that rather than introducing another variable that is not defined (extreme events) that the language already commonly used be included so it would read as follows: a. “Limit the impact of instability, uncontrolled separation, or Cascading. 2. On exclusion “n.” local generator output controls should be included as well  
 General Notes: Colorado Springs Utilities does not agree with the exclusion list in the proposed definition. We do not think that it is reasonable or prudent to create a comprehensive list of exclusions. There will always be just one more exception that will force us to continue to modify the list of exclusions. Also, if it is not explicitly defined as an exception then by default it is automatically included whether it could affect reliability or not. The definition should clearly define what a RAS so as to include those schemes identified as essential to reliability. The only implicit exclusion we would recommend would be to exclude protection schemes that meet the definition of a RAS and are explicitly covered under other NERC reliability standards. Utilities would then use the definition to make sure that essential protection systems that meet the definition are included and document any further assumptions or judgement used in delineating between RAS and non-RAS schemes. Trying to micro-manage every possible exclusion or inclusion we think is not realistic and should not be necessary.

Group

|   |
|---|
| Peak Reliability  |
| Jared Shakespeare   |
| No  |
| <p>The new exclusion (n) that reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing” excludes certain historical RAS actions such as AGC blocking. It is agreed some generator controls like AVR and PSS are not RAS. See added inclusion list below. Adding BES to the possible objectives can be confusing to interpret. It can be interpreted that RAS are restricted to BES elements when that is not the intention of the standard. Peak recommends either removing “BES” from possible objectives or adding “(including sub-100 kV facilities identified as necessary by the Reliability Coordinator)” as shown below. Note this language is consistent with IRO-002-4 R3. It might be beneficial in the background information to include that RAS is distinctly different than industry standard (IEEE) definition for System Integrated Protection Scheme (SIPS). Proposed definition: A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:</p> <ul style="list-style-type: none"> <li>• Meet requirements identified in the NERC Reliability Standards;</li> <li>• Maintain Bulk Electric System (BES) (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) stability;</li> <li>• Maintain acceptable BES (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) voltages;</li> <li>• Maintain acceptable BES (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) power flows;</li> <li>• Limit the impact of Cascading or extreme events.</li> </ul> <p>The following constitute RAS:</p> <ul style="list-style-type: none"> <li>• AGC blocking</li> <li>• Fast valving</li> </ul> <p>The following do not individually constitute a RAS:</p> <ol style="list-style-type: none"> <li>a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements</li> <li>b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays</li> <li>c. Out-of-step tripping and power swing blocking</li> <li>d. Automatic Reclosing schemes</li> <li>e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service</li> <li>f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated</li> <li>g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device</li> <li>h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched</li> <li>i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open</li> <li>j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)</li> <li>k. Automatic sequences that proceed when manually initiated solely by a System Operator</li> </ol> |

Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations) n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Individual

Hamid Zakery

Calpine Corp

No

Calpine appreciated the efforts by the Special Protection System SDT team. We support the idea of having a sigle clear definition. However, it is not clear why existing widely used SPS definition is being revised to be replaced with a Remedial Action Scheme (RAS)that is not commonly known. We believe this change will create even more confusion as there is no clarrification for what is an "scheme". Is it a protection system, turbine control, static VAR Compensator(SVC) operation, large shunt capacitor controls connected at the BES level to maintain acceptable BES voltage. We suggest adding the word protective to the RAS definition as following " A protective scheme designed to detect predetermined ...." This may clarify potential confusions may be caused by listing all protection system schemes in the " do not individually constitute as RAS" section.

Individual

David Thorne

Pepco Holdings Inc

Yes

Individual

Andrew Z. Pusztai

American Transmission Company, LLC

Yes

However, ATC suggests the addition of parenthetical verbiage similar to today's SPS definition to exclusion (c). The suggested change to exclusion (c) would read "Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)."

Individual

Mark Wilson

Independent Electricity System Operator

Yes

|  |
|--|
| Group  |
| MRO NERC Standards Review Forum  |
| Joe DePoorter  |
|  |
| No   |
| <p>Please consider the following: Exclusion item (c) - Retain the parenthetical text from the existing SPS Definition in the new RAS Definition, namely “c. Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)”. There is an existing power swing blocking scheme where this parenthetical language is key for clarifying the SPS exclusion. Exclusion item (e) – Add reverse power relays to include this clarification, with wording like, “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, overload, or reverse power to protect the Element against damage by removing it from service.” Add Exclusion item (o) – Add an exclusion item that identifies some minimum impact thresholds for applicability to NERC Reliability Standards (e.g. Section 215, EOP-004-2 disturbance reporting). For example, if an RAS would not cause any loss of firm load, any loss of BES generation, any damage to BES Elements, any loss of nuclear plant off-site power, any widespread instability, uncontrollable separation or cascading, etc., then it is not be subject to any RAS requirements in NERC Reliability Standards. Implementation Plan – In almost all circumstances the twelve month timeframe for the RAS definition or revised Reliability Standard should be sufficient for the introduction of new RAS or identification of existing scheme as RAS. However, it is also possible the identification of an existing scheme as RAS might require BES system upgrades that could take years to design, approve, and build (e.g. 7 year provision in the TPL-001-4 standard). Therefore, consider including a provision in the Implementation Plan of an effective date of seven years for existing schemes that were not previously identified as SPS.</p> |
| Individual   |
| Jonathan Meyer   |
| Idaho Power  |
|  |
| Yes  |
|  |
| Individual   |
| Terry Harbour  |
| MidAmerican Energy   |
|  |
| No   |
| <p>Exclusion item (c) - Retain the parenthetical text from the existing SPS Definition in the new RAS Definition, namely “c. Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)”. There is an existing power swing blocking scheme where this parenthetical language is key for clarifying the SPS exclusion. Exclusion item (e) – Add reverse</p>   |

power relays to include this clarification, with wording like, “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, overload, or reverse power to protect the Element against damage by removing it from service.” Add Exclusion item (o) – Add an exclusion item that identifies some minimum impact thresholds for applicability to NERC Reliability Standards (e.g. Section 215, or the EOP-004-2 disturbance reporting standard). If an RAS would not cause loss of load and or generation of more than 100 MW then the event would be local and would not meet the need for “special” consideration in the NERC standards. Criteria consistent with NERC standard EOP-004-2 such as the following could be considered: 1. No automatic firm load shedding  $\geq$  100 MW (excluding automatic undervoltage or underfrequency load shedding schemes needed to meet other NERC standards). 2. No Loss of firm load for  $\geq$  15 Minutes or greater than  $\geq$  100 MW. 3. No total generation loss, within one minute, of  $\geq$  100 MW. Implementation Plan – Identification of existing or new RAS /SPS schemes might require BES system upgrades that could take years to design, approve, and build (e.g. 7 year provision in the TPL-001-4 standard). Therefore, consider including a provision in the Implementation Plan of an effective date of seven years for existing schemes that were not previously identified as SPS / RAS schemes.

Individual

Richard Pienkos

Consumers Energy Company

No

The sentence originally read “RAS accomplish one or more of the following objectives:”. This implies that it has to meet at least one of these criteria to be an applicable RAS. It was changed to read “RAS accomplish objectives such as:” . This now implies that this is a just a list of examples but there may be other objectives that apply. I was relying on this original wording to limit the compliance exposure to BES systems only. The way it is written now it can be interpreted to apply to schemes on the non-BES system. Consumers Energy will vote negative on this ballot until this wording is changed back or some other way is used to limit this definition to only BES schemes.

Group

Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing

Wayne Johnson

Yes

Group

Con Edison, Inc.

Kelly Dash

|  |
|--|
| No   |
| In PRC-024-1(X), "A. Introduction 5. Effective Date" was removed, and replaced by the Effective Date paragraph. This change is not only not indicated in the redline, but more importantly it removed the "phased-in" implementation of PRC-024-1 which was necessitated by the requirements of the standard. Under A.5 Effective Date: of PRC-025-1(X) the words "See Implementation Plan" were deleted. PRC-025-1(X) has its own Implementation Plan which is part of the standard's "package". However, to ensure clarity and avoid misunderstanding, suggest leaving "See Implementation Plan" in A.5. The Implementation Plan must be revised to be consistent with the intended revisions. It should be made clear that all aspects of the Implementation Plans for PRC-024-1 and PRC-025-1 will remain applicable to those standards.   |
| Individual   |
| Michelle D'Antuono   |
| Ingleside Cogeneration LP  |
| Yes  |
| Ingleside Cogeneration LP (ICLP) agrees that the latest version of the RAS definition is a distinct improvement over its predecessor. The removal of the catch-all inclusion for schemes that address "other Bulk Electric System (BES) reliability concerns" is the primary reason for our "Yes" vote this time around. With it, the definition inferred that every automated system that has even the most tenuous tie to reliability could be considered as RAS – which clearly is not the intent of this initiative. Another positive modification in our view is the new exclusion for generator control systems like AGC, PSS, AVR's, and governors. These clearly are not Remedial Action Schemes, but without the exclusion it is possible to construe them as such. While not affecting our vote, ICLP would like a better explanation to the elimination of categories of RAS – as originally recommended by the SPCS. The only response we saw was a statement that "informal feedback from many stakeholders" led to this decision. Perhaps there are very good reasons they were only shared with the project team, but the Standards Development Process is expected to be open and deliberative. The informal process is important in order to stimulate good ideas and discussion, but should not play a part in the review/ballot unless it is documented and vetted by all participating stakeholders. |
| Individual   |
| Michael Moltaned   |
| ITC  |
| No   |
| Remove "such as" from "RAS accomplish objectives such as:". Exclusion A should remove "BES". E.g. non-BES transformers connected to BES lines or buses have fault protection which must trip for transformer faults to accomplish RAS objectives. However, these should be excluded from RAS. Reverse power relaying on distribution-transmission interface should be excluded from RAS. This could be a separate exclusion or a modification to Exclusion J.  |



|   |
|---|
| Group   |
| PacifiCorp  |
| Sandra Shaffer  |
|   |
| No  |
| <p>Western requests the SDT to re-consider an additional exclusion for “cross-tripping schemes within the same station”. We continue to believe such a simplistic localized scheme should be outside the purview of a RAS and its associated scrutiny and approval, which particularly does not lend itself to the operating horizon. By and large, implementation of a cross-trip within the same station is utilized to mitigate a thermal SOL by tripping another element in lieu of the overloaded element. Not only does this action mitigate a thermal SOL, it most often improves the robustness and reliability of the remaining BES system to deliver firm commitments. The proposed exceptions are appropriate; however, they are still inadequate. The end effect of the proposed RAS definition includes any protection action and/or scheme that is beyond standard/historical individual relaying protection package functions, thereby limiting the ‘art’ of system protection to include the objective of ‘maximizing the robustness of the remaining BES system’. On this basis, Western suggests the SDT reconsider the definition strictly including “reconfiguring a System(s)”. The suggestion of excluding “cross-tripping schemes within the same station” for sake of mitigating a potential thermal overload is more benign should it fail to operate than failure of the currently proposed exclusion of “out-of-step tripping and power swing blocking”, as an example. Further, the definition does not delineate lower risk “localized” schemes. Consequently, there is no expeditious avenue to implement a localized benign scheme within a reasonable timeframe for the operating horizon. This is a real issue. As example, following the flood of 2011, Western had transmission lines toppling in standing water and needed to quickly implement a cross-trip scheme to facilitate needed and urgent outages for maintenance/repair (within days). Western suggests the SDT recognize “localized” benign schemes either outside the scrutiny of a RAS all together, or at minimum, allow such schemes to be implemented for 1 year with the caveat that the scheme be vetted through an expedited stakeholder process. If the “localized” scheme ultimately must receive RAS review and scrutiny, it should be done expeditiously. Currently, the WECC RASRS attempts to streamline “localized’ schemes.</p> |
| Individual  |
| Philip R. Kleckley  |
| South Carolina Electric & Gas Co.   |
|   |
| Yes   |
|   |
| Individual  |
| Sonya Green-Sumpter   |
| South Carolina Electric & Gas   |
| Agree   |

|  |
|--|
| Individual   |
| Karen Webb   |
| City of Tallahassee  |
| Agree  |
|  |
| Individual   |
| Sergio Banuelos  |
| Tri-State Generation and Transmission Association, Inc.  |
|  |
| No   |
| <p>1. The first bullet after the opening definition seems very vague; especially since the next three bullets are examples of those requirements referenced in the first bullet. 2. The fifth bullet does not seem to apply unless an entity has identified the “Cascading or extreme events” resulting from some “predetermined System conditions.” Tri-State believes that it may be better to revert to the previous language that included “abnormal or,” i.e., “A scheme designed to detect abnormal or predetermined System conditions...” 3. Reword exclusion (e.) such that local monitoring can be used to disconnect other Elements than the one Element being monitored as long as communications to a different location is not required. For example, “Schemes applied locally for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to remove a local Element from service to protect it against damage.” 4. While Tri-State agrees with exclusion (e.) in principle (with our suggested wording changes), it seems that the inclusion of “overvoltage, or overload” is in conflict with the third and fourth bullets in the main definition. Perhaps “the use of communication” needs to be included in parts of the definition. 5. Tri-State thinks exclusion (f.) should start with the word “Automatic” so as not to be confused with remote manual control. 6. Exclusion (g.) seems to be in conflict with the last phrase of exclusion (f.). 7. Exclusion (h.) seems to be in conflict with the last phrase of exclusion (f.).</p> |
| Group  |
| Santee Cooper  |
| Shawn Tom Abrams   |
|  |
| No   |
| <p>“Santee disagrees with using RAS as a replacement for SPS. An SPS is used as an automatic system designed to detect abnormal or pre-determined system conditions and take pre-planned corrective action. This term applies to and is referenced in numerous guides, procedures and protocols.” “The term SPS should not be based upon normal operational schemes like a RAS. These are “special” systems designed to maintain reliability until solutions can be added to remove or “exit” their changes. We also anticipate other Reliability Coordinators having to go through a similar effort in regards to the SPS terminology change.”</p>  |

|   |
|---|
| Individual  |
| Gul Khan  |
| Oncor Electric Delivery LLC   |
|   |
| Yes   |
|   |
| Individual  |
| Chris Scanlon   |
| Exelon Companies  |
|   |
| Yes   |
| We think the following should be considered. Exclusion “e” specifically includes “transformer top-oil temperature”. Other common transformer protection such as “winding temperature” and “loss of cooling” measure distinctly different parameters from top oil temperature but share a similar goal. These protection schemes seem conspicuous by their absence from exclusion “e” . They are arguably covered under the “but not limited to” clause but especially the former seems common enough that it merits specific mention.   |
| Individual  |
| Venona Greaff   |
| Occidental Chemical Corporation   |
| Agree   |
| Ingleside Cogeneration, LP  |
| Group   |
| SPP Standards Review Group  |
| Robert Rhodes   |
|   |
| Yes   |
| We appreciate the effort of the drafting team in developing the proposed revised definition. The new revision is much clearer. The expansion of the list of exclusions has been a big help. Whenever the NERC Glossary of Terms is referenced in the standard and in the Background and FAQ document, the full name is used – Glossary of Terms Used in NERC Reliability Standards. This is the case with one exception, in the 1st line of the answer to the 1st question under the FAQ section of the Background and FAQ document. Please make the appropriate change here. |
| Individual  |
| Bill Fowler   |
| City of Tallahassee   |
|   |
| No  |

In order to eliminate uncertainty, TAL believes criteria should be established that defines acceptable BES power flows.

Group

Dominion NERC Compliance Policy

Randi Heise

No

Section D: Under section d; reclosing should not be capitalized, this is not a defined term in the NERC Glossary of terms. Section F: Although the SDT responded to Dominion’s prior comments, Dominion believes that the SDT’s response is deficient.” in that Dominion does not support the inclusion of the phrase, "and that are located at and monitor quantities solely at the same station as the Element being switched or regulated." Why does it make a difference whether the controller is local or remote? The advent of high-speed phase measurement units (PMUs) and faster computer systems will eventually allow wide area control. This will become essential as the customer's load characteristic evolves (less voltage and frequency dependency means local PSSs will be less effective). We are concerned that the definition in general will hamper innovation. Right now there are schemes that control LTC’s and capacitors to minimize losses. Certainly these are not RAS. There are EMS controls such as what PJM uses that dispatch generation precontingency to avoid overloads/voltage problems. These are not RAS either. Eventually computer EMS systems will become fast and robust enough to drop load or reconfigure the system so quickly that wide area blackouts will be virtually eliminated. Recall that only 500 MWs of load drop would have stopped the 2003 blackout. Therefore wide area systems that generically react to problems (not designed for a single specific contingency (if line A opens, do xyz action)) should not be RAS. Section N: Dominion does not agree with addition of (n) as written. The first paragraph of the definition states “A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation.... So, to the extent automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, or speed governing is used in such a scheme it can’t be excluded. It may help clarify if the SDT expanded upon the intent of the phrase “The following do not individually constitute a RAS” General comment: The elimination of SPS terminology , the move to one term- RAS and the addition of exclusion language only complicates the historical view on “special” schemes. This change will cause many US utilities burden due to references to SPS’s that will result in numerous revisions to existing compliance documentation, training programs, reference prints, and scheme application operating procedures. The majority of US utilities and at Protection Conferences the term SPS is used while the minority (most in WECC region) use the term RAS. Many times these schemes are made up primarily of protective relays to implement “special” applications. This change in definition is unnecessary and only introduces more questions when exclusions are introduced.

Individual

John Merrell

Tacoma Power

No

Regarding one comment previously submitted by Tacoma Power, the drafting team responded that they “did not try to create an exhaustive list of examples.” While Tacoma Power acknowledges that it is difficult to create an exhaustive list, Tacoma Power does believe that the following clarification, either in the definition, or in the FAQ document, needs to be made. The following type of scheme should be explicitly identified as an exclusion since classification of this type of scheme has been a gray area; clarification is needed: “Thermal protection systems intended to mitigate thermal damage, within expected system re-dispatch response times, such as 10 minutes or greater.” However, if the drafting team intended for this type of scheme generally to be RAS, then clarification is also needed. In the proposed RAS definition, change “MW and Mvar” to “MW and/or Mvar.” Otherwise, the definition suggests that both MW and Mvar must be adjusted, which might not be the case for every RAS. In the proposed RAS definition, would automatic sequences that proceed when manually initiated solely by plant personnel, substation operators, or similar on-site personnel still be considered an exclusion if directed by a System Operator? Tacoma Power believes that the answer should be yes. In the FAQ document, under “Automatic Reclosing schemes,” the drafting team stated that “system reconfiguration which transfers the load to another source typically would be a RAS.” Tacoma Power believes that system reconfiguration primarily intended to restore load following a loss of that load should typically fall under the exclusion (d). When the FAQ document states that “system reconfiguration which transfers the load to another source typically would be a RAS,” Tacoma Power understands this would be a true statement if and only if the system reconfiguration is intended to support one of the five bulleted objectives identified in the proposed RAS definition. In the FAQ document, under “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service,” Tacoma Power maintains that, in lieu of removing the Element from service due to an overload, taking action such as adjusting generation, especially at the same location (power plant) of the overload, would equally satisfy the exclusion, especially if removal of the Element, after time delay, is employed as a fallback. Regarding the implementation plan for PRC-024-1(X), it appears that the 40%, 60%, and 80% milestones contained in PRC-024-1 may have been eliminated. If this is not true, please provide clarification as to where these milestones will be documented if PRC-024-1(X) is approved. In any event, these milestones should be maintained.

Group

National Grid

Michael Jones

No

Please add the following item, to the lists of items, that do not individually constitute a RAS:  
"The controllers at each terminal of an High Voltage direct current (HVdc) Facility, that may or

may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility." Rationale: HVdc controllers performing the intended control functions for that HVdc Facility, should have equal treatment as FACTS controllers in the exclusion list. HVdc control functions such as: Pole Loss Compensation, Fast Metallic Return, and Permanent Mode Shift Compensation should be excludable controllers.

Individual

Scott Langston

City of Tallahassee

No

In order to eliminate uncertainty, TAL believes criteria should be established that defines acceptable BES power flows.

Individual

Laurie Williams

PNM Resources Inc.

Yes

PNM Resources appreciates the work of the Drafting team and would request that there be a clarification that 'Temporary Outage Action Plans' or 'TOAPs' (used in the TRE/ERCOT area) are not included in the definition of RAS. It appears that TOAPs used by ERCOT entities would primarily be subject to 'Exclusion E' as they are temporary schemes that would switch elements based on voltage or to avoid thermal overload on non-faulted elements. They could additionally fall under 'Exclusion K' and would take the action that would normally be executed by System Operators manually. TOAPs are developed to protect against a temporary condition that could arise during a planned maintenance outage which are utilized widely in the TRE/ERCOT area and in PNM Resources' opinion should not be considered RAS which would then require that any Temporary Outage Action Plan would trigger CIP-002-5 inclusion of a BES asset to evaluate and have to apply CIP protections to systems not typically included in CIP scope.

Individual

Chris de Graffenried

Con Edison, Inc.

Agree

Northeast Power Coordinating Council (NPCC)

Individual

John Pearson/Matt Goldberg

ISO New England

No

Exclusion “c” should be revised to include the word “stable” before the words “power swing blocking” so that it reads “c. Out-of-step tripping and stable power swing blocking.” This is because the exclusion should only apply to stable power swing blocking and not all power swing blockings. Exclusion “e” Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service, unless the operation of the scheme is relied on to allow reliable operation at more stressed transfers on the system. Example: Loss of a 345 kV line on an interface overloads a parallel 115 kV line at a transfer of 1,000 MW. If the 115 kV line overload is detected by a scheme and removed from service, the interface can then reliably transfer 1,500 MW. This should be considered to be a RAS. Exclusion “j” currently reads “Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage).” This language is confusing because the first phrase describes schemes designed to prevent an island from forming but the parenthetical describes actions taken after an island is formed. To avoid this confusion, exclusion “j” should be revised to read: “j. Schemes that protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage.” For exclusion “m,” in response to a comment we had made during the previous commenting period, the Standard Drafting Team explained that “Exclusion (m) is consistent with present industry practices and the drafting team declined to make the suggested change. The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.” While we agree with the Standard Drafting Team’s explanation, in order to clearly reflect that explanation in the RAS definition, exclusion “m” should read: “m. Sub-synchronous resonance (SRR) protection schemes that directly detect and only take local action due to sub-synchronous quantities (e.g., currents or torsional oscillations).” The definition should decouple all possible HVDC Converter controls from the RAS definition. Add an additional Exclusion to RAS definition for HVDC Based on NERC Terms of Glossary - Facility, here is the suggested exclusion language: The controllers at each terminal of an High Voltage direct current (HVdc) Facility, that may or may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility.

Group

Florida Municipal Power Agency

Carol Chinn

Yes

FMFA agrees with the changes to the definition of Remedial Action Scheme but maintains that a thorough review of all standards should be conducted to look for uses of the terms Protection System(s) and protection system(s) to determine if it was intended to include SPS/RAS as part of the requirement. Simply removing the statement “These schemes are not

Protection Systems; however, they may share components with Protection Systems” does not accomplish the same objective. As an example, PER-005-1 R3.1 may or may not be interpreted to include Remedial Actions Schemes.

Group

Tennessee Valley Authority

Dennis Chastain

No

We agree that using a single term should help bring the industry toward a common understanding/usage of the term. However, we disagree with the revised draft definition. Bullets 2-5 can be interpreted to cover objectives beyond NERC Reliability Standards, when taken in context with the first bullet. The scope of the definition should be limited to applications that are relevant to the NERC Reliability Standards in which the term is used. We think it’s appropriate to address exclusions, however when the exclusion list is this long (and perhaps growing) it highlights the challenge in developing a good base definition for what constitutes a RAS NERC-wide. An alternative would be to “catalog” the RAS exclusions in a separate NERC reference document that could be revised without revising the base RAS definition. We feel that the implementation period should be extended to 5 years or more for existing schemes that are categorized as RAS by this definition change. Since the definition affects many additional standards, this could entail more work than anticipated to ensure full compliance with each one under the new definition.

Individual

Catherine Wesley

PJM Interconnection

Yes

Individual

Jo-Anne Ross

Manitoba Hydro

Yes

Group

ACES Standards Collaborators

Brian Van Gheem

No

(1) We agree with the need to modify the existing definition of SPS and RAS and that use of a single term will provide a more consistent use in applicable NERC standards and among the



various NERC regions. We also appreciate the efforts of the SDT and incorporating many of our previous comments and recommendations into this latest proposed definition. However, we still feel the proposed definition still needs further clarification with its objectives and list of exclusions. (2) The definition identifies that one objective of a RAS is to “Meet requirements identified in the NERC Reliability Standards”. As we identified in previously submitted comments, the reference of this term is ambiguous, and the SDT should remove it from the definition. According to the consideration of comments posted from the last comment period, the SDT believes this term needs to highlight the importance of risk on reliability when a RAS fails to operate or operate not as designed. We believe such an importance is already captured in the other objectives such as “Limit the impact of Cascading or extreme events” and “Maintain Bulk Electric System (BES) stability”. Moreover, operation failure of the RAS measures the effectiveness of the actions taken by the RAS, not why an entity would install and maintain a RAS on their system. Furthermore, NERC declares on its website that its standards “define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities.” NERC and its regions assign these requirements to registered entities, not to individual BES elements or related system components. (3) The SDT added the NERC-defined term, “System Operator”, to exclusion “k” in the list of items that do not individually constitute a RAS. We believe the possibility exists when non-NERC certified operators, such as a local TO operations center in PJM that performs switching, could manually initiate a sequence that further leads to activation of automated operations. This possibility exists due to the staffing requirements listed in the requirements of NERC Standard PER-003-1. We suggest the SDT add “...or personnel under their direct supervision” to this exclusion item to address this possibility. (4) The addition of “extreme events” to the last objective bullet is ambiguous and confusing. The objectives already cover Cascading and stability in other bullets. What other “extreme events” is the definition intended to cover? System islanding or separation? If so, then just state specifically these extreme events and remove the vague term “extreme events”. (5) We would like to thank the SDT on its continual efforts to include comments from industry during the development of this definition and this opportunity to comment.

Group

PacifiCorp

Sandra Shaffer

No

(1) PacifiCorp strongly suggests further revision of the proposed RAS definition to provide an exclusion for schemes that trip adjacent circuits within a single substation, commonly referred to as cross-tripping schemes. Cross-trip schemes are often hard-wired or implemented with simple mirrored-bit type communications between relays in a single substation. These schemes are employed in instances when tripping of an element or elements in addition to or instead of the directly-monitored system element within a substation will provide superior electrical performance. Cross-trip schemes utilize simple Boolean logic, and system impacts of

the schemes are typically local in nature. It is therefore PacifiCorp's contention that inclusion of these schemes in the RAS catalogs will do little to improve system performance or reliability, and further, their inclusion may hinder the transmission planning process by encumbering planners with information that is not useful. PacifiCorp does recognize the importance of capturing the actions of these cross-trip schemes in transmission system planning models; however this is best accomplished in contingency definitions. (2) The RAS definition does not provide any delineation between schemes that may have a significant impact on the bulk electric system and schemes that have limited impacts to the local system. PacifiCorp suggests that the drafting team reconsider inclusion of the Local Area, Wide Area, and Safety Net scheme designations in the RAS definition. These designations have been successfully defined and implemented within the WECC RRO territory with good results. As such, PacifiCorp suggests adoption of the WECC criteria for scheme delineation utilizing TPL criteria violations, load and generation impacts to provide clear and consistent delineation between the various types of schemes.

Individual

William Temple

Northeast Utilities

Agree

Northeast Power Coordinating Council

Individual

Steve Johnson

WAPA

No

Western requests the SDT re-consider an additional exclusion for "cross-tripping schemes within the same station". We continue to believe such a simplistic localized hard-wired scheme should be outside the purview of a RAS and its associated scrutiny and approval, which particularly does not lend itself to the operating horizon. By and large, implementation of a cross-trip within the same station is utilized to mitigate a thermal SOL by tripping another element in lieu of the overloaded element. Not only does this action mitigate an SOL, it most often improves the robustness and reliability of the remaining BES system to deliver firm commitments. Without such exclusion, the SOL element often must be opened pre-contingent, thus further degrading the robustness of the BES. The proposed exceptions are appropriate; however, they are still inadequate. The end effect of the proposed RAS definition basically captures any protection action and/or scheme that is beyond standard/historical individual relaying protection package functions, thereby limiting the 'art' of system protection to 'maximize the robustness of the post-contingent BES system'. On this basis, Western suggests the SDT reconsider the definition's strict inclusion of "reconfiguring a System(s)". Western's suggestion of excluding "cross-tripping schemes within the same station" for sake of mitigating a potential SOL is more benign should it fail to operate than failure of the currently proposed exclusion of "out-of-step tripping and power swing blocking", as an example. Did the last SPS definition's use of the language "acceptable

voltage, or power flow” intend to capture the granularity of localized SOLs versus larger and/or regional BES impacts? Further, the definition does not delineate lower risk “localized” schemes. Consequently, there is no expeditious approval mechanism to implement a benign localized scheme within a reasonable timeframe for the operating horizon. This is a real issue. Several years ago following spring flooding, Western had transmission lines toppling in standing water and needed to quickly implement a cross-trip scheme to facilitate needed and urgent outages for maintenance/repair (within days). Without such flexibility, customer service and reliability is further reduced. Western suggests the SDT recognize “localized” benign schemes either outside the scrutiny of a RAS all together, or at minimum, allow such schemes to be implemented for 1 year with the caveat that the scheme be vetted through an expedited stakeholder process. If the “localized” scheme ultimately must receive RAS review and scrutiny, it should be done expeditiously. Currently, the WECC RASRS are attempting to streamline “localized’ schemes.

**Additional Comments:**

**Associated Electric Cooperative, Inc.**

**Phil Hart**

**1. No**

**Comments:**

The purpose of this project is stated as, "...assist the industry with the application of the revised definition." However the current revision seems to be providing more confusion than clarity. Because both the Inclusions and Exclusions are so broad, it would seem everything is first included in a RAS, and then excluded, leaving nothing. AECI would suggest the SDT at least limit such broad inclusions to begin with, and in turn this would require fewer exclusions on the back-end.

# Consideration of Comments

## Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)

The Special Protection Systems Drafting Team thanks all commenters who submitted feedback on the revised definition of Remedial Action Scheme. The revised definition was posted for a 45-day public comment period from August 29, 2014 through October 14, 2014. Stakeholders were asked to provide feedback on the revised definition through a special electronic comment form. There were 46 responses, including comments from approximately 126 different people from approximately 92 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at [valerie.agnew@nerc.net](mailto:valerie.agnew@nerc.net). In addition, there is a NERC Reliability Standards Appeals Process.<sup>1</sup>

### Summary of Changes

#### Definition:

Lower-cased the word 'reclosing' in Exclusion 'd' because it is not a defined term in the Glossary of Terms Used in NERC Reliability Standards.

#### Implementation Plan:

Updated the list of Reliability Standards being revised to use the single defined term RAS with the new NERC numbering system.

Removed PRC-024-1 and PRC-005-1 from the list of revised Reliability Standards to avoid any complications related to the timing of their associated implementations.

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<sup>1</sup> The appeals process is in the Standard Processes Manual: [http://www.nerc.com/comm/SC/Documents/Appendix\\_3A\\_StandardsProcessesManual.pdf](http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf)

**Background and FAQ:**

The Background and FAQ document was updated to reflect the changes and additions made to the proposed definition

**Unresolved Minority Views:**

A few commenters questioned the general formatting of the definition and the need for an exclusion list.

The drafting team explained the definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS. Note, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety.

**Index to Questions, Comments, and Responses**

1. Do you agree with the revised definition of a Remedial Action Scheme (RAS)? If not, please provide the basis for your disagreement and your proposed revisions. .... 13

**The Industry Segments are:**

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

| Group/Individual  |                  | Commenter                                 | Organization                         |                   | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |
|-------------------|------------------|---|--------------------------------------|-------------------|--------------------------------|---|---|---|---|---|---|---|---|----|
|                   |                  |   |                                      |                   | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1.                | Group            | Guy Zito                                  | Northeast Power Coordinating Council |                   | X                              | X | X |   | X | X |   | X | X | X  |
| Additional Member |                  | Additional Organization                   | Region                               | Segment Selection |                                |   |   |   |   |   |   |   |   |    |
| 1.                | Alan Adamson     | New York State Reliability Council, LLC   | NPCC                                 | 10                |                                |   |   |   |   |   |   |   |   |    |
| 2.                | David Burke      | Orange and Rockland Utilities Inc.        | NPCC                                 | 3                 |                                |   |   |   |   |   |   |   |   |    |
| 3.                | Greg Campoli     | New York Independent System Operator      | NPCC                                 | 2                 |                                |   |   |   |   |   |   |   |   |    |
| 4.                | Sylvain Clermont | Hydro-Quebec TransEnergie                 | NPCC                                 | 1                 |                                |   |   |   |   |   |   |   |   |    |
| 5.                | Kelly Dash       | Consolidated Edison Co. of New York, Inc. | NPCC                                 | 1                 |                                |   |   |   |   |   |   |   |   |    |
| 6.                | Gerry Dunbar     | Northeast Power Coordinating Council      | NPCC                                 | 10                |                                |   |   |   |   |   |   |   |   |    |
| 7.                | Mike Garton      | Dominion Resources Services, Inc.         | NPCC                                 | 5                 |                                |   |   |   |   |   |   |   |   |    |
| 8.                | Kathleen Goodman | ISO - New England                         | NPCC                                 | 2                 |                                |   |   |   |   |   |   |   |   |    |
| 9.                | Michael Jones    | National Grid                             | NPCC                                 | 1                 |                                |   |   |   |   |   |   |   |   |    |
| 10.               | Mark Kenny       | Northeast Utilities                       | NPCC                                 | 1                 |                                |   |   |   |   |   |   |   |   |    |
| 11.               | Helen Lainis     | Independent Electricity System Operator   | NPCC                                 | 2                 |                                |   |   |   |   |   |   |   |   |    |

| Group/Individual | Commenter                | Organization                              |                                 |                          | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |  |  |
|------------------|--------------------------|---|---------------------------------|--------------------------|--------------------------------|---|---|---|---|---|---|---|---|----|--|--|
|                  |                          |   |                                 |                          | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |
| 12               | Alan MacNaughton         | New Brunswick Power Corporation           | NPCC                            | 9                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 13               | Bruce Metruck            | New York Power Authority                  | NPCC                            | 6                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 14               | Lee Pedowicz             | Northeast Power Coordinating Council      | NPCC                            | 10                       |                                |   |   |   |   |   |   |   |   |    |  |  |
| 15               | Robert Pellegrini        | The United Illuminating Company           | NPCC                            | 1                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 16               | Si Truc Phan             | Hydro-Quebec TransEnergie                 | NPCC                            | 1                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 17               | David Ramkalawan         | Ontario Power Generation, Inc.            | NPCC                            | 5                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 18               | Brian Robinson           | Utility Services                          | NPCC                            | 8                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 19               | Ayesha Sabouba           | Hydro One Networks Inc.                   | NPCC                            | 1                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 20               | Brian Shanahan           | National Grid                             | NPCC                            | 1                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 21               | Wayne Sipperly           | New York Power Authority                  | NPCC                            | 5                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 22               | Ben Wu                   | Orange and Rockland Utilities Inc.        | NPCC                            | 1                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 23               | Peter Yost               | Consolidated Edison Co. of New York, Inc. | NPCC                            | 3                        |                                |   |   |   |   |   |   |   |   |    |  |  |
| 2.               | Group                    | Joe DePoorter                             | MRO NERC Standards Review Forum |                          | X                              | X | X | X | X | X |   |   |   |    |  |  |
|                  | <b>Additional Member</b> | <b>Additional Organization</b>            | <b>Region</b>                   | <b>Segment Selection</b> |                                |   |   |   |   |   |   |   |   |    |  |  |
| 1.               | Amy Casucelli            | Xcel Energy                               | MRO                             | 1, 3, 5, 6               |                                |   |   |   |   |   |   |   |   |    |  |  |
| 2.               | Chuck Wicklund           | Otter Tail Power                          | MRO                             | 1, 3, 5                  |                                |   |   |   |   |   |   |   |   |    |  |  |
| 3.               | Dan Inman                | Minnkota Power Coop                       | MRO                             | 1, 3, 5, 6               |                                |   |   |   |   |   |   |   |   |    |  |  |



| Group/Individual | Commenter                | Organization                   | Registered Ballot Body Segment |                          |   |   |   |   |   |   |   |    |  |  |
|------------------|--------------------------|--------------------------------|--------------------------------|--------------------------|---|---|---|---|---|---|---|----|--|--|
|                  |                          |                                | 1                              | 2                        | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |
| 4.               | Dave Rudolph             | Basin Electric Power Coop      | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 5.               | Kayleigh Wilkerson       | Lincoln Electric System        | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 6.               | Jodi Jensen              | WAPA                           | MRO                            | 1, 6                     |   |   |   |   |   |   |   |    |  |  |
| 7.               | Joe DePoorter            | Madison Gas & Electric         | MRO                            | 3, 4, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 8.               | Ken Goldsmith            | Alliant Energy                 | MRO                            | 4                        |   |   |   |   |   |   |   |    |  |  |
| 9.               | Mahmood Safi             | Omaha Public Power District    | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 10.              | Marie Knox               | MISO                           | MRO                            | 2                        |   |   |   |   |   |   |   |    |  |  |
| 11.              | Mike Brytowski           | Great River Energy             | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 12.              | Randi Nyholm             | Minnesota Power                | MRO                            | 1, 5                     |   |   |   |   |   |   |   |    |  |  |
| 13.              | Scott Nickels            | Rochester Public Utilities     | MRO                            | 4                        |   |   |   |   |   |   |   |    |  |  |
| 14.              | Terry Harbour            | MidAmerican Energy             | MRO                            | 1, 3, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 15.              | Tom Breene               | Wisconsin Public Service       | MRO                            | 3, 4, 5, 6               |   |   |   |   |   |   |   |    |  |  |
| 16.              | Tony Eddleman            | Nebraska Public Power District | MRO                            | 1, 3, 5                  |   |   |   |   |   |   |   |    |  |  |
| 3.               | Group                    | Kelly Dash                     | Con Edison, Inc.               |                          | X |   | X |   | X | X |   |    |  |  |
|                  | <b>Additional Member</b> | <b>Additional Organization</b> | <b>Region</b>                  | <b>Segment Selection</b> |   |   |   |   |   |   |   |    |  |  |
| 1.               | Edward Bedder            | Orange and Rockland Utilities  | NPCC                           | NA                       |   |   |   |   |   |   |   |    |  |  |
| 4.               | Group                    | Shawn Tom Abrams               | Santee Cooper                  |                          | X |   | X |   | X | X |   |    |  |  |
|                  | <b>Additional Member</b> | <b>Additional Organization</b> | <b>Region</b>                  | <b>Segment Selection</b> |   |   |   |   |   |   |   |    |  |  |

| Group/Individual | Commenter                | Organization                         |                                 |                          |  | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
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|                  |                          |                                      |                                 |                          |  | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |  |  |  |
| 1.               | S. Tom Abrams            | Santee Cooper                        | SERC                            | 1, 3, 5, 6               |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 2.               | Glenn Stephens           | Santee Cooper                        | SERC                            | 1, 3, 5, 6               |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 3.               | Rene Free                | Santee Cooper                        | SERC                            | 1, 3, 5, 6               |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 5.               | Group                    | Robert Rhodes                        | SPP Standards Review Group      |                          |  |                                | X | X | X | X | X |   |   |   |    |  |  |  |  |  |
|                  | <b>Additional Member</b> | <b>Additional Organization</b>       | <b>Region</b>                   | <b>Segment Selection</b> |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 1.               | Kevin Foflygen           | City Utilities of Springfield        | SPP                             | 1, 4                     |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 2.               | Allan George             | Sunflower Electric Power Corporation | SPP                             | 1                        |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 3.               | Shannon Mickens          | Southwest Power Pool                 | SPP                             | 2                        |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 4.               | James Nail               | City of Independence, MO             | SPP                             | 3, 5                     |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 6.               | Group                    | Randi Heise                          | Dominion NERC Compliance Policy |                          |  |                                | X |   | X |   | X | X |   |   |    |  |  |  |  |  |
|                  | <b>Additional Member</b> | <b>Additional Organization</b>       | <b>Region</b>                   | <b>Segment Selection</b> |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 1.               | Randi Heise              | Dominion                             | NPCC                            | 6                        |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 2.               | Mike Garton              | Dominion                             | NPCC                            | 5                        |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 3.               | Connie Lowe              | Dominion                             | RFC                             | 6                        |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 4.               | Louis Slade              | Dominion                             | SERC                            | 5                        |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |
| 5.               | Larry Nash               | Dominion                             | SERC                            | 1, 3                     |  |                                |   |   |   |   |   |   |   |   |    |  |  |  |  |  |

| Group/Individual  |                   | Commenter                      |      | Organization                   |  | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |
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|                   |                   |                                |      |                                |  | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 6                 | Chip Humphrey     | Dominion                       | RFC  | 5                              |  |                                |   |   |   |   |   |   |   |   |    |
| 7.                | Group             | Michael Jones                  |      | National Grid                  |  | X                              |   | X |   |   |   |   |   |   |    |
| Additional Member |                   | Additional Organization        |      | Region                         |  | Segment Selection              |   |   |   |   |   |   |   |   |    |
| 1                 | Brian Shanahan    | National Grid                  | NPCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 8.                | Group             | Carol Chinn                    |      | Florida Municipal Power Agency |  | X                              |   | X | X | X | X |   |   |   |    |
| Additional Member |                   | Additional Organization        |      | Region                         |  | Segment Selection              |   |   |   |   |   |   |   |   |    |
| 1.                | Tim Beyrle        | City of New Smyrna Beach       | FRCC | 4                              |  |                                |   |   |   |   |   |   |   |   |    |
| 2.                | Jim Howard        | Lakeland Electric              | FRCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 3.                | Greg Woessner     | Kissimmee Utility Authority    | FRCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 4.                | Lynne Mila        | City of Clewiston              | FRCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 5.                | Randy Hahn        | Ocala Utility Services         | FRCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 6.                | Don Cuevas        | Beaches Energy Services        | FRCC | 1                              |  |                                |   |   |   |   |   |   |   |   |    |
| 7.                | Stanley Rząd      | Keys Energy Services           | FRCC | 4                              |  |                                |   |   |   |   |   |   |   |   |    |
| 8.                | Mark Schultz      | City of Green Cove Springs     | FRCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 9.                | Matt Culverhouse  | City of Bartow                 | FRCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 10.               | Tom Reedy         | Florida Municipal Power Pool   | FRCC | 6                              |  |                                |   |   |   |   |   |   |   |   |    |
| 11.               | Steven Lancaster  | Beaches Energy Services        | FRCC | 3                              |  |                                |   |   |   |   |   |   |   |   |    |
| 12.               | Mike Blough       | Kissimmee Utility Services     | FRCC | 5                              |  |                                |   |   |   |   |   |   |   |   |    |
| 13.               | Richard Bachmeier | Gainesville Regional Utilities | FRCC | 1                              |  |                                |   |   |   |   |   |   |   |   |    |
| 9.                | Group             | Dennis Chastain                |      | Tennessee Valley Authority     |  | X                              |   | X |   | X | X |   |   |   |    |
| Additional Member |                   | Additional Organization        |      | Region                         |  | Segment Selection              |   |   |   |   |   |   |   |   |    |

| Group/Individual |                          | Commenter                                       | Organization                          |                          | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |
|------------------|--------------------------|---|---------------------------------------|--------------------------|--------------------------------|---|---|---|---|---|---|---|---|----|
|                  |                          |   |                                       |                          | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1.               |                          | DeWayne Scott                                   | SERC                                  | 1                        |                                |   |   |   |   |   |   |   |   |    |
| 2.               |                          | Ian Grant                                       | SERC                                  | 3                        |                                |   |   |   |   |   |   |   |   |    |
| 3.               |                          | Brandy Spraker                                  | SERC                                  | 5                        |                                |   |   |   |   |   |   |   |   |    |
| 4.               |                          | Marjorie Parsons                                | SERC                                  | 6                        |                                |   |   |   |   |   |   |   |   |    |
| 10.              | Group                    | Brian Van Gheem                                 | ACES Standards Collaborators          |                          | X                              |   | X | X | X | X |   |   |   |    |
| 1                | Kevin Lyons              | Central Iowa Power Cooperative                  | MRO                                   | 1                        |                                |   |   |   |   |   |   |   |   |    |
| 2                | John Shaver              | Arizona Electric Power Cooperative              | WECC                                  | 1, 4, 5                  |                                |   |   |   |   |   |   |   |   |    |
| 3                | John Shaver              | Southwest Transmission Cooperative, Inc.        | WECC                                  | 1, 4, 5                  |                                |   |   |   |   |   |   |   |   |    |
| 4                | Ellen Watkins            | Sunflower Electric Power Corporation            | SPP                                   | 1                        |                                |   |   |   |   |   |   |   |   |    |
| 5                | Shari Heino              | Brazos Electric Power Cooperative, Inc.         | ERCOT                                 | 1, 5                     |                                |   |   |   |   |   |   |   |   |    |
| 6                | Mark Ringhausen          | Old Dominion Electric Cooperative               | SERC                                  | 3, 4                     |                                |   |   |   |   |   |   |   |   |    |
| 7                | Chip Koloini             | Golden Spread Electric Cooperative, Inc.        | SPP                                   | 3, 5                     |                                |   |   |   |   |   |   |   |   |    |
| 8                | Ryan Strom               | Buckeye Power, Inc.                             | RFC                                   | 3, 4, 5                  |                                |   |   |   |   |   |   |   |   |    |
| 9                | Bob Solomon              | Hoosier Energy Rural Electric Cooperative, Inc. | RFC                                   | 1                        |                                |   |   |   |   |   |   |   |   |    |
| 11.              | Group                    | Phil Hart                                       | Associated Electric Cooperative, Inc. |                          | X                              |   | X |   | X | X |   |   |   |    |
|                  | <b>Additional Member</b> | <b>Additional Organization</b>                  | <b>Region</b>                         | <b>Segment Selection</b> |                                |   |   |   |   |   |   |   |   |    |
| 1                |                          | Central Electric Power Cooperative              | SERC                                  | 1, 3                     |                                |   |   |   |   |   |   |   |   |    |
| 2                |                          | KAMO Electric Cooperative                       | SERC                                  | 1, 3                     |                                |   |   |   |   |   |   |   |   |    |

| Group/Individual | Commenter                                     | Organization       | Registered Ballot Body Segment  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
|------------------|---|--------------------|---|---|---|---|---|---|---|---|---|----|--|--|--|--|--|--|--|--|
|                  |   |                    | 1   | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |  |  |  |  |  |  |  |  |
| 3                | M & A Electric Power Cooperative              | SERC               | 1, 3  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 4                | Northeast Missouri Electric Power Cooperative | SERC               | 1, 3  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 5                | N. W. Electric Power Cooperative, Inc.        | SERC               | 1, 3  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 6                | Sho-Me Power Electric Power Cooperative       | SERC               | 1, 3  |   |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 12.              | Individual                                    | Janet Smith        | Arizona Public Service Co   | X |   | X |   | X | X |   |   |    |  |  |  |  |  |  |  |  |
| 13.              | Individual                                    | Kaleb Brimhall     | Colorado Springs Utilities  | X |   | X |   | X | X |   |   |    |  |  |  |  |  |  |  |  |
| 14.              | Individual                                    | Jared Shakespeare  | Peak Reliability  | X |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 15.              | Individual                                    | Wayne Johnson      | Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing | X |   | X |   | X | X |   |   |    |  |  |  |  |  |  |  |  |
| 16.              | Individual                                    | Sandra Shaffer     | PacifiCorp  |   |   |   |   |   | X |   |   |    |  |  |  |  |  |  |  |  |
| 17.              | Individual                                    | Sandra Shaffer     | PacifiCorp  |   |   |   |   |   | X |   |   |    |  |  |  |  |  |  |  |  |
| 18.              | Individual                                    | Thomas Foltz       | American Electric Power   | X |   | X |   | X | X |   |   |    |  |  |  |  |  |  |  |  |
| 19.              | Individual                                    | Barbara Kedrowski  | Wisconsin Electric Power Co   |   |   | X | X | X |   |   |   |    |  |  |  |  |  |  |  |  |
| 20.              | Individual                                    | Amy Casuscelli     | Xcel Energy   | X |   | X |   | X | X |   |   |    |  |  |  |  |  |  |  |  |
| 21.              | Individual                                    | Hamid Zakery       | Calpine Corp  |   |   |   |   | X |   |   |   |    |  |  |  |  |  |  |  |  |
| 22.              | Individual                                    | David Thorne       | Pepco Holdings Inc  | X |   | X |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 23.              | Individual                                    | Andrew Z. Pusztai  | American Transmission Company, LLC  | X |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 24.              | Individual                                    | Mark Wilson        | Independent Electricity System Operator   |   | X |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 25.              | Individual                                    | Jonathan Meyer     | Idaho Power   | X |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 26.              | Individual                                    | Terry Harbour      | MidAmerican Energy  | X |   | X |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 27.              | Individual                                    | Richard Pienkos    | Consumers Energy Company  |   |   | X | X | X |   |   |   |    |  |  |  |  |  |  |  |  |
| 28.              | Individual                                    | Michelle D'Antuono | Ingleside Cogeneration LP   |   |   |   |   | X |   |   |   |    |  |  |  |  |  |  |  |  |
| 29.              | Individual                                    | Michael Moltaned   | ITC   | X |   |   |   |   |   |   |   |    |  |  |  |  |  |  |  |  |
| 30.              | Individual                                    | Philip R. Kleckley | South Carolina Electric & Gas Co.   | X |   | X |   | X |   |   |   |    |  |  |  |  |  |  |  |  |

| Group/Individual |            | Commenter                  | Organization  | Registered Ballot Body Segment |   |   |   |   |   |   |   |   |    |
|------------------|------------|----------------------------|---|--------------------------------|---|---|---|---|---|---|---|---|----|
|                  |            |                            |   | 1                              | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 31.              | Individual | Sonya Green-Sumpter        | South Carolina Electric & Gas                           | X                              |   | X |   | X | X |   |   |   |    |
| 32.              | Individual | Karen Webb                 | City of Tallahassee                                     |                                |   |   |   | X |   |   |   |   |    |
| 33.              | Individual | Sergio Banuelos            | Tri-State Generation and Transmission Association, Inc. | X                              |   | X |   | X |   |   |   |   |    |
| 34.              | Individual | Gul Khan                   | Oncor Electric Delivery LLC                             | X                              |   |   |   |   |   |   |   |   |    |
| 35.              | Individual | Chris Scanlon              | Exelon Companies  | X                              |   | X |   | X | X |   |   |   |    |
| 36.              | Individual | Venona Greaff              | Occidental Chemical Corporation                         |                                |   |   |   |   |   | X |   |   |    |
| 37.              | Individual | Bill Fowler                | City of Tallahassee                                     |                                |   | X |   |   |   |   |   |   |    |
| 38.              | Individual | John Merrell               | Tacoma Power  | X                              |   | X | X | X | X |   |   |   |    |
| 39.              | Individual | Scott Langston             | City of Tallahassee                                     | X                              |   |   |   |   |   |   |   |   |    |
| 40.              | Individual | Laurie Williams            | PNM Resources Inc.                                      | X                              |   | X |   |   |   |   |   |   |    |
| 41.              | Individual | Chris de Graffenried       | Con Edison, Inc.  | X                              |   | X |   | X | X |   |   |   |    |
| 42.              | Individual | John Pearson/Matt Goldberg | ISO New England   |                                | X |   |   |   |   |   |   |   |    |
| 43.              | Individual | Catherine Wesley           | PJM Interconnection                                     |                                |   |   |   |   |   |   |   |   |    |
| 44.              | Individual | Jo-Anne Ross               | Manitoba Hydro  | X                              |   | X |   | X | X |   |   |   |    |
| 45.              | Individual | William Temple             | Northeast Utilities                                     | X                              |   |   |   |   |   |   |   |   |    |
| 46.              | Individual | Steve Johnson              | WAPA  | X                              |   | X |   |   |   |   |   |   |    |

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

**Summary Consideration:**

| Organization                    | Agree | Supporting Comments of "Entity Name"        |
|---------------------------------|-------|---|
| Occidental Chemical Corporation | Agree | Ingleside Cogeneration, LP                  |
| Northeast Utilities             | Agree | Northeast Power Coordinating Council        |
| Con Edison, Inc.                | Agree | Northeast Power Coordinating Council (NPCC) |

1. Do you agree with the revised definition of a Remedial Action Scheme (RAS)? If not, please provide the basis for your disagreement and your proposed revisions.

#### Summary Consideration:

A commenter asserted that ‘reclosing’ in Exclusion ‘d’ should not be capitalized because it is not a defined term in the Glossary of Terms Used in NERC Reliability Standards. The drafting team agreed and made the suggested change.

A few commenters questioned the general formatting of the definition and the need to contain an exclusion list. The drafting team explained the definition must be broad enough to include the variety of system conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS. The drafting team noted that, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety. For these reasons, the drafting team retained the exclusion list.

A commenter questioned the list of objectives in the definition stating that the first objective “Meet requirements identified in the NERC Reliability Standards” should be the only objective. The commenter asserted that the definition of RAS should be limited to applications relevant to the NERC Reliability Standards. The drafting team asserts that maintaining the reliability of the BES is the overarching principle and that there are instances when schemes are applied to satisfy objectives beyond Reliability Standards. These schemes need similar review and oversight regarding design and implementation adequacy, coordination, misoperation, unintended consequences, etc. as schemes applied for satisfying Reliability Standards and therefore also need to be classified as RAS.

Several commenters wanted more examples provided in Exclusion ‘e’, which already specified “transformer top-oil temperature”. Commenters suggested other common schemes such as reverse power, transformer winding temperature, and loss of cooling. The drafting team agreed that the examples provided would not individually be considered RAS and modified the FAQ document to include several more. The drafting team further explained that they did not intend to develop an all-inclusive list of examples in each of the exclusions.



A commenter questioned the inclusion of the BES modifier in the list of objectives. The commenter wanted to include non-BES Facilities as identified by the Reliability Coordinator. The drafting team explained that the definition of RAS does not necessarily exclude sub-100 kV facilities. Facilities that impact the BES can be subject to NERC jurisdiction. If an entity such as a Reliability Coordinator determines that sub-100kV facilities should be included in the BES, they can submit a request to the BES Exception Process for inclusion. The drafting team asserts that regardless of the objective, schemes applied on non-BES systems that do impact the BES reliability would be RAS; however, schemes applied on non-BES systems that do not have a BES reliability impact would not be RAS.

A commenter questioned the inclusion of the BES modifier in Exclusion ‘a.’ The drafting team agreed that Protection Systems installed for the purpose of detecting Faults on non-BES Elements do not meet the definition of RAS, and thus are not subject to the RAS-related NERC Reliability Standards. The drafting team did not remove the BES modifier.

Numerous commenters described various scheme scenarios asking the drafting team’s opinion on whether or not the scenarios would be deemed RAS based on the definition. The drafting team attempted to apply the definition to the limited descriptions provided.

Several commenters questioned why the RAS definition does not provide delineation between schemes that have different levels of impact on the BES. The drafting team explained that the classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. The drafting team will address this issue during the standards development phase of the project in 2015.

Several commenters raised concerns with the modifications the drafting team made to the Implementation Plans for PRC-024-1 and PRC-025-1. The drafting team explained that they did not intend to truncate the implementation of PRC-024-1 and PRC-025-1, and to avoid any complications related to the timing of the implementations, the team removed those standards from this project. The transition from the use of the definition of SPS to RAS for PRC-024-1 and PRC-025-1 will occur at a later date.

| # | Organization | Yes/<br>No | Question 1 Comment  |
|---|--------------|------------|---|
| 1 | PacifiCorp   | No         | 1. PacifiCorp strongly suggests further revision of the proposed RAS definition to provide an exclusion for schemes that trip adjacent circuits within a single substation, commonly referred to as cross-tripping schemes. Cross-trip schemes are often hard-wired or implemented with simple mirrored-bit type communications between relays in a single substation. These schemes are employed in instances when |

| #  | Organization                 | Yes/<br>No | Question 1 Comment   |
|--|------------------------------|------------|--|
|  |                              |            | <p>tripping of an element or elements in addition to or instead of the directly-monitored system element within a substation will provide superior electrical performance. Cross-trip schemes utilize simple Boolean logic, and system impacts of the schemes are typically local in nature. It is therefore PacifiCorp’s contention that inclusion of these schemes in the RAS catalogs will do little to improve system performance or reliability, and further, their inclusion may hinder the transmission planning process by encumbering planners with information that is not useful. PacifiCorp does recognize the importance of capturing the actions of these cross-trip schemes in transmission system planning models; however this is best accomplished in contingency definitions.</p> <p>2. The RAS definition does not provide any delineation between schemes that may have a significant impact on the bulk electric system and schemes that have limited impacts to the local system. PacifiCorp suggests that the drafting team reconsider inclusion of the Local Area, Wide Area, and Safety Net scheme designations in the RAS definition. These designations have been successfully defined and implemented within the WECC RRO territory with good results. As such, PacifiCorp suggests adoption of the WECC criteria for scheme delineation utilizing TPL criteria violations, load and generation impacts to provide clear and consistent delineation between the various types of schemes.</p> |
| <p><b>Response:</b> Thank you for your comment.</p> <p>1. The drafting team contends that performing switching in the same substation (including transfer- or cross-trip schemes) that trip Elements other than the impacted Element is too broad of an exclusion.</p> <p>2. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. This issue will be addressed by the RAS classification during the standards development phase of the project in 2015.</p> |                              |            |  |
| 2  | ACES Standards Collaborators | No         | <p>We agree with the need to modify the existing definition of SPS and RAS and that use of a single term will provide a more consistent use in applicable NERC standards and among the various NERC regions. We also appreciate the efforts of the SDT and incorporating many of our previous comments and recommendations into this latest proposed definition. However, we still feel the proposed definition still needs further clarification with its objectives and list of exclusions.</p> <p>1. The definition identifies that one objective of a RAS is to “Meet requirements identified in the NERC Reliability Standards”. As we identified in previously submitted comments, the reference of this term is</p>   |

| # | Organization | Yes/<br>No | Question 1 Comment   |
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|   |              |            | <p>ambiguous, and the SDT should remove it from the definition. According to the consideration of comments posted from the last comment period, the SDT believes this term needs to highlight the importance of risk on reliability when a RAS fails to operate or operate not as designed. We believe such an importance is already captured in the other objectives such as “Limit the impact of Cascading or extreme events” and “Maintain Bulk Electric System (BES) stability”. Moreover, operation failure of the RAS measures the effectiveness of the actions taken by the RAS, not why an entity would install and maintain a RAS on their system. Furthermore, NERC declares on its website that its standards “define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities.” NERC and its regions assign these requirements to registered entities, not to individual BES elements or related system components.</p> <ol style="list-style-type: none"> <li>2. The SDT added the NERC-defined term, “System Operator”, to exclusion “k” in the list of items that do not individually constitute a RAS. We believe the possibility exists when non-NERC certified operators, such as a local TO operations center in PJM that performs switching, could manually initiate a sequence that further leads to activation of automated operations. This possibility exists due to the staffing requirements listed in the requirements of NERC Standard PER-003-1. We suggest the SDT add “...or personnel under their direct supervision” to this exclusion item to address this possibility.</li> <li>3. The addition of “extreme events” to the last objective bullet is ambiguous and confusing. The objectives already cover Cascading and stability in other bullets. What other “extreme events” is the definition intended to cover? System islanding or separation? If so, then just state specifically these extreme events and remove the vague term “extreme events”.</li> </ol> <p>We would like to thank the SDT on its continual efforts to include comments from industry during the development of this definition and this opportunity to comment.</p> |
|   |              |            | <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team does not agree with the commenter that the objective is ambiguous. Many RAS are installed for the purpose of satisfying the requirements of NERC Reliability Standards; consequently the drafting team asserts that the stated objective is valid and reasonable to include in the objective list. The definition by itself imposes no requirements on RAS owners.</li> <li>2. The FERC-approved definition of System Operator is: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time. The drafting team contends this definition covers your concern.</li> </ol>  |

| # | Organization               | Yes/<br>No | Question 1 Comment  |
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|   |                            |            | <p>3. The drafting team notes that the term “extreme events” is commonly used in the TPL family of standards. The drafting team purposefully used the term “extreme events” because it is broader than “System islanding or separation,” and there are RAS that mitigate such TPL extreme events that should be recognized by the definition.</p>   |
| 3 | Colorado Springs Utilities | No         | <ol style="list-style-type: none"> <li>1. The last bullet of the definition, before all the exclusions, says “Limit the impact of Cascading or extreme events. We recommend that rather than introducing another variable that is not defined (extreme events) that the language already commonly used be included so it would read as follows: a. Limit the impact of instability, uncontrolled separation, or Cascading.</li> <li>2. On exclusion “n.” local generator output controls should be included as well.</li> <li>3. General Notes: Colorado Springs Utilities does not agree with the exclusion list in the proposed definition. We do not think that it is reasonable or prudent to create a comprehensive list of exclusions. There will always be just one more exception that will force us to continue to modify the list of exclusions. Also, if it is not explicitly defined as an exception then by default it is automatically included whether it could affect reliability or not. The definition should clearly define what a RAS so as to include those schemes identified as essential to reliability. The only implicit exclusion we would recommend would be to exclude protection schemes that meet the definition of a RAS and are explicitly covered under other NERC reliability standards. Utilities would then use the definition to make sure that essential protection systems that meet the definition are included and document any further assumptions or judgment used in delineating between RAS and non-RAS schemes. Trying to micro-manage every possible exclusion or inclusion we think is not realistic and should not be necessary.</li> </ol> |
|   |                            |            | <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team notes that the term “extreme events” is commonly used in the TPL family of standards. The drafting team purposefully used the term “extreme events” because it is broader than “instability” or “uncontrolled separation,” and there are RAS that mitigate “extreme events” that should be recognized by the definition.</li> <li>2. The drafting team is not certain what you mean by “local generator output controls.” If you are referring to a generator run-back scheme that operates due to a problem within the generation facility, then it is most likely not a RAS; however, if the generator run-back scheme responds to conditions on the BES outside of the generation facility, then it would be a RAS.</li> <li>3. The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that</li> </ol>  |

| #  | Organization  | Yes/<br>No | Question 1 Comment  |
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| commonly applied protection and control systems are not unintentionally included as RAS. Note, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety.   |   |            |   |
| 4  | Tri-State Generation and Transmission Association, Inc. | No         | <ol style="list-style-type: none"> <li>1. The first bullet after the opening definition seems very vague; especially since the next three bullets are examples of those requirements referenced in the first bullet.</li> <li>2. The fifth bullet does not seem to apply unless an entity has identified the “Cascading or extreme events” resulting from some “predetermined System conditions.” Tri-State believes that it may be better to revert to the previous language that included “abnormal or,” i.e., “A scheme designed to detect abnormal or predetermined System conditions...”</li> <li>3. Reword exclusion (e.) such that local monitoring can be used to disconnect other Elements than the one Element being monitored as long as communications to a different location is not required. For example, “Schemes applied locally for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to remove a local Element from service to protect it against damage.”</li> <li>4. While Tri-State agrees with Exclusion ‘e’ in principle (with our suggested wording changes), it seems that the inclusion of “overvoltage, or overload” is in conflict with the third and fourth bullets in the main definition. Perhaps “the use of communication” needs to be included in parts of the definition.</li> <li>5. Tri-State thinks Exclusion ‘f’ should start with the word “Automatic” so as not to be confused with remote manual control.</li> <li>6. Exclusion ‘g’ seems to be in conflict with the last phrase of Exclusion ‘f.’</li> <li>7. Exclusion ‘h’ seems to be in conflict with the last phrase of Exclusion ‘f.’</li> </ol> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team does not agree with the commenter that the objective is vague. Many RAS are installed for the purpose of satisfying the requirements of NERC Reliability Standards; consequently the drafting team asserts that the stated objective is valid and reasonable to include in the objective list. The definition by itself imposes no requirements on RAS owners.</li> <li>2. The drafting team disagrees with the suggested change and declines to modify the definition.</li> <li>3. The drafting team contends that performing switching in the same substation (including transfer- or cross-trip schemes) that trip Elements other than the protected Element is a System reconfiguration and is therefore a RAS. Reconfiguring the System can be a critical factor in reliability and merits the review and oversight associated with RAS.</li> <li>4. The objective of many RAS are to address overloads or over-voltages. Exclusion ‘e’ specifically identifies schemes that are installed to protect an Element by removing that Element from service. Communication is not a required element of a RAS.</li> </ol> |   |            |   |

| #  | Organization    | Yes/<br>No | Question 1 Comment  |
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|  |                 |            | <p>5. A manual operation whether local or remote is never a RAS. The drafting team declines to make the suggested change.</p> <p>6. Exclusions ‘f’ and ‘g’ are complementary in that ‘f’ provides a broad exception for local controls at the same station while ‘g’ provides a specific exclusion for FACTS control of shunt devices at one or more other stations.</p> <p>7. Exclusions ‘f’ and ‘h’ are complementary in that ‘f’ provides a broad exception for local controls at the same station while ‘h’ provides a specific exclusion for manual back-up control of shunt devices at one or more stations.</p>  |
| 5  | Santee Cooper   | No         | <p>Santee disagrees with using RAS as a replacement for SPS. An SPS is used as an automatic system designed to detect abnormal or pre-determined system conditions and take pre-planned corrective action. This term applies to and is referenced in numerous guides, procedures and protocols. The term SPS should not be based upon normal operational schemes like a RAS. These are “special” systems designed to maintain reliability until solutions can be added to remove or “exit” their changes. We also anticipate other Reliability Coordinators having to go through a similar effort in regards to the SPS terminology change.</p>   |
| <p><b>Response:</b> Thank you for your comments. The terms RAS and SPS are currently synonymous and interchangeable terms in the Glossary of Terms Used in NERC Reliability Standards. Please read the FAQ for more explanation regarding the use of the term RAS.</p>   |                 |            |   |
| 6  | Calpine Corp    | No         | <p>Calpine appreciated the efforts by the Special Protection System SDT team. We support the idea of having a single clear definition. However, it is not clear why existing widely used SPS definition is being revised to be replaced with a Remedial Action Scheme (RAS) that is not commonly known. We believe this change will create even more confusion as there is no clarification for what is an "scheme".</p> <p>Is it a protection system, turbine control, static VAR Compensator (SVC) operation, large shunt capacitor controls connected at the BES level to maintain acceptable BES voltage. We suggest adding the word protective to the RAS definition as following: " A protective scheme designed to detect predetermined ...." This may clarify potential confusions may be caused by listing all protection system schemes in the "do not individually constitute as RAS" section.</p> |
| <p><b>Response:</b> Thank you for your comments. The terms RAS and SPS are currently synonymous and interchangeable terms in the Glossary of Terms Used in NERC Reliability Standards. The drafting team declines to make the suggested changes. Please refer to the FAQ for more explanation regarding the use of the term RAS.</p> |                 |            |   |
| 7  | ISO New England | No         | <ol style="list-style-type: none"> <li>1. Exclusion “c” should be revised to include the word “stable” before the words “power swing blocking” so that it reads “c. Out-of-step tripping and stable power swing blocking.” This is because the exclusion should only apply to stable power swing blocking and not all power swing blockings.</li> <li>2. Exclusion “e” Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element</li> </ol>  |

| #  | Organization | Yes/<br>No | Question 1 Comment   |
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|  |              |            | <p>against damage by removing it from service, unless the operation of the scheme is relied on to allow reliable operation at more stressed transfers on the system. Example: Loss of a 345 kV line on an interface overloads a parallel 115 kV line at a transfer of 1,000 MW. If the 115 kV line overload is detected by a scheme and removed from service, the interface can then reliably transfer 1,500 MW. This should be considered to be a RAS.</p> <p>3. Exclusion “j” currently reads “Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage).” This language is confusing because the first phrase describes schemes designed to prevent an island from forming but the parenthetical describes actions taken after an island is formed. To avoid this confusion, exclusion “j” should be revised to read: “j. Schemes that protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage.”</p> <p>4. For exclusion “m,” in response to a comment we had made during the previous commenting period, the Standard Drafting Team explained that “Exclusion (m) is consistent with present industry practices and the drafting team declined to make the suggested change. The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.” While we agree with the Standard Drafting Team’s explanation, in order to clearly reflect that explanation in the RAS definition, exclusion “m” should read: “m. Sub-synchronous resonance (SRR) protection schemes that directly detect and only take local action due to sub-synchronous quantities (e.g., currents or torsional oscillations).”</p> <p>5. The definition should decouple all possible HVDC Converter controls from the RAS definition. Add an additional Exclusion to RAS definition for HVDC. Based on NERC Terms of Glossary - Facility, here is the suggested exclusion language: The controllers at each terminal of an High Voltage direct current (HVdc) Facility, that may or may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility.</p> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team intends for this exclusion to apply to both stable and unstable power swing blocking.</li> <li>2. If the scheme exists only to protect the line from damage caused by overload, it would be excluded by ‘e’ and not be a RAS. But if operation of the scheme is relied upon to increase the transfer limit or possibly prevent a violation of a TPL standard</li> </ol> |              |            |  |

| # | Organization       | Yes/<br>No | Question 1 Comment   |
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|   |                    |            | <p>requirement, the functional application is consistent with that of a RAS and beyond the intent of exclusion ‘e’, and the scheme would be considered a RAS. Additionally, if the scheme monitors the status of the 345kV line to arm or initiate the 115kV line tripping, it would be a RAS irrespective of the specific objective. The drafting team declines to make the suggested modification.</p> <ol style="list-style-type: none"> <li>3. The parenthetical represents an example of a why anti-islanding protection is applied. Anti-islanding protection is not intended to prevent an island from forming but to detect and de-energize an island.</li> <li>4. The proposed RAS definition is intended to exclude schemes that directly detect sub-synchronous quantities and take either local or non-local action(s). Therefore, the drafting team declines to make the changes proposed by the commenter.</li> <li>5. The drafting team asserts that HVdc converter controls do not meet the definition of RAS. Such controls maintain correct operation and provide protection for the HVdc Facility itself, and are not implemented to take corrective actions based on predetermined system conditions to meet objectives such as those described in the RAS definition. An HVdc control scheme that takes corrective actions, such as backing down power transfer on the HVdc Facility following a contingency to avoid overload of another BES Element, may be part of a RAS. The suggested exclusion is unnecessary; therefore, the drafting team declines to make the proposed changes.</li> </ol>   |
| 8 | MidAmerican Energy | No         | <ol style="list-style-type: none"> <li>1. Exclusion item (c) - Retain the parenthetical text from the existing SPS Definition in the new RAS Definition, namely “c. Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)”. There is an existing power swing blocking scheme where this parenthetical language is key for clarifying the SPS exclusion.</li> <li>2. Exclusion item (e) - Add reverse power relays to include this clarification, with wording like, “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, overload, or reverse power to protect the Element against damage by removing it from service.”</li> <li>3. Add Exclusion item (o) - Add an exclusion item that identifies some minimum impact thresholds for applicability to NERC Reliability Standards (e.g. Section 215, or the EOP-004-2 disturbance reporting standard). If an RAS would not cause loss of load and or generation of more than 100 MW then the event would be local and would not meet the need for “special” consideration in the NERC standards. Criteria consistent with NERC standard EOP-004-2 such as the following could be considered:             <ol style="list-style-type: none"> <li>1. No automatic firm load shedding 100 MW (excluding automatic undervoltage or underfrequency load shedding schemes needed to meet other NERC standards).</li> <li>2. No Loss of firm load for 15 Minutes or greater 100 MW.</li> <li>3. No total generation loss, within one minute, of 100 MW.</li> </ol> </li> </ol> |



| #  | Organization  | Yes/No | Question 1 Comment   |
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|    |   |        | 4. Implementation Plan - Identification of existing or new RAS /SPS schemes might require BES system upgrades that could take years to design, approve, and build (e.g. 7 year provision in the TPL-001-4 standard). Therefore, consider including a provision in the Implementation Plan of an effective date of seven years for existing schemes that were not previously identified as SPS / RAS schemes. |
|    | <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team contends the existing sentence “The following do not individually constitute a RAS” accomplishes what you are requesting and declines to make the suggested change.</li> <li>2. While we agree that the example you provide would not individually be considered RAS, the drafting team did not intend to develop an all-inclusive list of examples in each of the exclusions. The drafting team agrees that a reverse power relay by itself would not constitute a RAS.</li> <li>3. Your comment appears to address classification types. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS; therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. This issue will be addressed during the standards development phase of the project in 2015.</li> <li>4. TPL-001-4 anticipates construction of major transmission and/or generation facilities to achieve compliance. That may require significant permitting effort as well as budgeting, design, scheduling and construction, etc. RAS are often used exactly because they can be implemented more quickly and cheaply and with less overall effort than the major system additions anticipated by TPL-001-4. The drafting team does not agree that an existing scheme newly defined as a RAS would require major system upgrades or 7 years to complete. The drafting team declines to make the suggested change.</li> </ol> |        |  |
| 9  | City of Tallahassee   | No     | In order to eliminate uncertainty, TAL believes criteria should be established that defines acceptable BES power flows.  |
|    | <p><b>Response:</b> Thank you for your comment. The RAS Definition is not the appropriate place to address this issue. Acceptable BES power flows are addressed in standards; e.g., FAC standards, or may be based on defined operating limits; e.g., System Operating Limits.</p>  |        |  |
| 10 | City of Tallahassee   | No     | In order to eliminate uncertainty, TAL believes criteria should be established that defines acceptable BES power flows.  |
|    | <p><b>Response:</b> Thank you for your comment. The RAS Definition is not the appropriate place to address this issue. Acceptable BES power flows are addressed in standards; e.g., FAC standards, or may be based on defined operating limits; e.g., System Operating Limits.</p>  |        |  |
| 11 | Con Edison, Inc.  | No     | In PRC-024-1(X), "A. Introduction 5. Effective Date" was removed, and replaced by the Effective Date paragraph. This change is not only not indicated in the redline, but more importantly it removed the “phased-in” implementation of PRC-024-1 which was necessitated by the requirements of the standard. Under A.5  |

| #   | Organization                         | Yes/<br>No | Question 1 Comment  |
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|   |                                      |            | <p>Effective Date: of PRC-025-1(X) the words “See Implementation Plan” were deleted. PRC-025-1(X) has its own Implementation Plan which is part of the standard’s “package.” However, to ensure clarity and avoid misunderstanding, suggest leaving “See Implementation Plan” in A.5. The Implementation Plan must be revised to be consistent with the intended revisions. It should be made clear that all aspects of the Implementation Plans for PRC-024-1 and PRC-025-1 will remain applicable to those standards.</p>   |
| <p><b>Response:</b> Thank you for your comment. The drafting team did not intend to truncate the implementation of PRC-024-1 and PRC-025-1. To avoid any complications related to the timing of the implementation, PRC-024-1 and PRC-025-1 have been removed from the project, and transition from the use of the definition of SPS to RAS will occur at a later date.</p>   |                                      |            |   |
| 12  | Northeast Power Coordinating Council | No         | <ol style="list-style-type: none"> <li>In PRC-024-1(X), A. Introduction 5. Effective Date was removed, and replaced by the Effective Date paragraph. This change is not only not indicated in the redline, but more importantly it removed the “phased-in” implementation of PRC-024-1 which was necessitated by the requirements of the standard. Is the intent to remove the “phase-in” percentages by the single effective date indicated by the Effective Date paragraph in PRC-024-1(X)? Under A.5 Effective Date: of PRC-025-1(X) the words “See Implementation Plan” were deleted. PRC-025-1(X) has its own Implementation Plan which is part of the standard’s “package.” However, to ensure clarity and avoid misunderstanding, suggest leaving “See Implementation Plan” in A.5. The Implementation Plan must be revised to be consistent with the intended revisions. It should be made clear that all aspects of the Implementation Plans for PRC-024-1 and PRC-025-1 will remain applicable to those standards.</li> <li>In part (b) on page 1, what is meant by “distributed relays”? Are “distributed relays” intended to be distribution system relays? The wording needs clarification.</li> <li>Please add the following to “The following do not individually constitute a RAS:” list: The controllers at each terminal of a High Voltage direct current (HVdc) Facility that may or may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility.</li> </ol> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>The drafting team did not intend to truncate the implementation of PRC-024-1 and PRC-025-1. To avoid any complications related to the timing of the implementation, PRC-024-1 and PRC-025-1 have been removed from the project, and transition from the use of the definition of SPS to RAS will occur at a later date.</li> <li>Distributed relays are individual relays which make independent Load shed decisions based on applied settings and localized voltage and/or current inputs. Distributed relays can be employed on transmission or distribution systems, or both.</li> </ol> |                                      |            |   |

| #  | Organization                    | Yes/<br>No | Question 1 Comment   |
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|    |                                 |            | <p>3. The drafting team asserts that HVdc converter controls do not meet the definition of RAS. Such controls maintain correct operation and provide protection for the HVdc Facility itself, and are not implemented to take corrective actions based on predetermined system conditions to meet objectives such as those described in the RAS definition. An HVdc control scheme that takes corrective actions, such as backing down power transfer on the HVdc Facility following a contingency to avoid overload of another BES Element, may be part of a RAS. The suggested exclusion is unnecessary; therefore, the drafting team declines to make the proposed changes.</p>   |
| 13 | National Grid                   | No         | <p>Please add the following item, to the lists of items, that do not individually constitute a RAS: "The controllers at each terminal of an High Voltage direct current (HVdc) Facility, that may or may not rely on communications with the other terminals of the same HVdc Facility, that perform the intended control functions for that HVdc Facility." Rationale: HVdc controllers performing the intended control functions for that HVdc Facility, should have equal treatment as FACTS controllers in the exclusion list. HVdc control functions such as: Pole Loss Compensation, Fast Metallic Return, and Permanent Mode Shift Compensation should be excludable controllers.</p>   |
|    |                                 |            | <p><b>Response:</b> Thank you for your comment. The drafting team asserts that HVdc converter controls do not meet the definition of RAS. Such controls maintain correct operation and provide protection for the HVdc Facility itself, and are not implemented to take corrective actions based on predetermined system conditions to meet objectives such as those described in the RAS definition. An HVdc control scheme that takes corrective actions, such as backing down power transfer on the HVdc Facility following a contingency to avoid overload of another BES Element, may be part of a RAS. The suggested exclusion is unnecessary; therefore, the drafting team declines to make the proposed changes.</p>   |
| 14 | MRO NERC Standards Review Forum | No         | <p>Please consider the following:</p> <ol style="list-style-type: none"> <li>1. Exclusion item (c) - Retain the parenthetical text from the existing SPS Definition in the new RAS Definition, namely "c. Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS)". There is an existing power swing blocking scheme where this parenthetical language is key for clarifying the SPS exclusion.</li> <li>2. Exclusion item (e) - Add reverse power relays to include this clarification, with wording like, "Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, overload, or reverse power to protect the Element against damage by removing it from service."</li> <li>3. Add Exclusion item (o) - Add an exclusion item that identifies some minimum impact thresholds for applicability to NERC Reliability Standards (e.g. Section 215, EOP-004-2 disturbance reporting). For</li> </ol> |

| #   | Organization | Yes/<br>No | Question 1 Comment  |
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|   |              |            | <p>example, if an RAS would not cause any loss of firm load, any loss of BES generation, any damage to BES Elements, any loss of nuclear plant off-site power, any widespread instability, uncontrollable separation or cascading, etc., then it is not be subject to any RAS requirements in NERC Reliability Standards.</p> <p>4. Implementation Plan - In almost all circumstances the twelve month timeframe for the RAS definition or revised Reliability Standard should be sufficient for the introduction of new RAS or identification of existing scheme as RAS. However, it is also possible the identification of an existing scheme as RAS might require BES system upgrades that could take years to design, approve, and build (e.g. 7 year provision in the TPL-001-4 standard). Therefore, consider including a provision in the Implementation Plan of an effective date of seven years for existing schemes that were not previously identified as SPS.</p> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>The drafting team contends the existing sentence “The following do not individually constitute a RAS” accomplishes what you are requesting and declines to make the suggested change.</li> <li>While we agree that the example you provide would not individually be considered RAS, the drafting team did not intend to develop an all-inclusive list of examples in each of the exclusions. The drafting team agrees that a reverse power relay by itself would not constitute a RAS.</li> <li>Your comment appears to address classification types. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS; therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. This issue will be addressed during the standards development phase of the project in 2015.</li> <li>TPL-001-4 anticipates construction of major transmission and/or generation facilities to achieve compliance. That may require significant permitting effort as well as budgeting, design, scheduling and construction, etc. RAS are often used exactly because they can be implemented more quickly and cheaply and with less overall effort than the major system additions anticipated by TPL-001-4. The drafting team does not agree that an existing scheme newly defined as a RAS would require major system upgrades or 7 years to complete. The drafting team declines to make the suggested change.</li> </ol> |              |            |   |
| 15  | Tacoma Power | No         | <ol style="list-style-type: none"> <li>Regarding one comment previously submitted by Tacoma Power, the drafting team responded that they “did not try to create an exhaustive list of examples.” While Tacoma Power acknowledges that it is difficult to create an exhaustive list, Tacoma Power does believe that the following clarification, either in the definition, or in the FAQ document, needs to be made. The following type of scheme should be explicitly identified as an exclusion since classification of this type of scheme has been a gray area; clarification is needed: “Thermal protection systems intended to mitigate thermal damage, within expected system re-</li> </ol>  |

| #  | Organization | Yes/<br>No | Question 1 Comment  |
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|  |              |            | <p>dispatch response times, such as 10 minutes or greater.” However, if the drafting team intended for this type of scheme generally to be RAS, then clarification is also needed.</p> <ol style="list-style-type: none"> <li>2. In the proposed RAS definition, change “MW and Mvar” to “MW and/or Mvar.” Otherwise, the definition suggests that both MW and Mvar must be adjusted, which might not be the case for every RAS.</li> <li>3. In the proposed RAS definition, would automatic sequences that proceed when manually initiated solely by plant personnel, substation operators, or similar on-site personnel still be considered an exclusion if directed by a System Operator? Tacoma Power believes that the answer should be yes.</li> <li>4. In the FAQ document, under “Automatic Reclosing schemes,” the drafting team stated that “system reconfiguration which transfers the load to another source typically would be a RAS.” Tacoma Power believes that system reconfiguration primarily intended to restore load following a loss of that load should typically fall under the exclusion (d). When the FAQ document states that “system reconfiguration which transfers the load to another source typically would be a RAS,” Tacoma Power understands this would be a true statement if and only if the system reconfiguration is intended to support one of the five bulleted objectives identified in the proposed RAS definition.</li> <li>5. In the FAQ document, under “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service,” Tacoma Power maintains that, in lieu of removing the Element from service due to an overload, taking action such as adjusting generation, especially at the same location (power plant) of the overload, would equally satisfy the exclusion, especially if removal of the Element, after time delay, is employed as a fallback.</li> <li>6. Regarding the implementation plan for PRC-024-1(X), it appears that the 40%, 60%, and 80% milestones contained in PRC-024-1 may have been eliminated. If this is not true, please provide clarification as to where these milestones will be documented if PRC-024-1(X) is approved. In any event, these milestones should be maintained.</li> </ol> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. Thermal protective systems are addressed by Exclusion ‘e’. Re-dispatch by a System Operator is a manual action and therefore does not meet the definition of a RAS.</li> <li>2. The parenthetical is an example of generation types and is consistent with the existing language of the SPS/RAS definition. The drafting team declines to make the suggested change.</li> <li>3. The drafting team agrees. Any individual taking manual action would not be a RAS (Exclusion ‘k’).</li> </ol> |              |            |   |

| #  | Organization                             | Yes/<br>No | Question 1 Comment  |
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|    |  |            | <ol style="list-style-type: none"> <li>4. If you are re-energizing the load then Exclusion 'd' does apply. System reconfiguration which transfers the load to another source for purposes other than load restoration typically would be a RAS.</li> <li>5. The drafting team contends that the scheme you describe in your example would be a RAS. Exclusion 'e' would not apply because you are taking action on an Element other than the overloaded Element.</li> <li>6. The drafting team did not intend to truncate the implementation of PRC-024-1. To avoid any complications related to the timing of the implementation, PRC-024-1 has been removed from the project and transition from the use of the definition of SPS to RAS will occur at a later date.</li> </ol>   |
| 16 | ITC                                      | No         | <ol style="list-style-type: none"> <li>1. Remove "such as" from "RAS accomplish objectives such as:"</li> <li>2. Exclusion A should remove "BES". E.g. non-BES transformers connected to BES lines or buses have fault protection which must trip for transformer faults to accomplish RAS objectives. However, these should be excluded from RAS.</li> <li>3. Reverse power relaying on distribution-transmission interface should be excluded from RAS. This could be a separate exclusion or a modification to Exclusion J.</li> </ol>   |
|    |  |            | <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team did not intend to make the list of objectives all-inclusive, they are examples so "such as" is necessary.</li> <li>2. The drafting team agrees that Protection Systems installed for the purpose of detecting Faults on non-BES Elements do not meet the definition of RAS, and thus are not subject to the RAS-related NERC Reliability Standards. The drafting team did not remove the BES modifier.</li> <li>3. The drafting team agrees that reverse power relaying on a distribution-transmission interface is not a RAS, Exclusions 'e' or 'j' would apply depending upon the application. No change to the exclusion is necessary.</li> </ol>   |
| 17 | Dominion<br>NERC<br>Compliance<br>Policy | No         | <ol style="list-style-type: none"> <li>1. Section D: Under section d; reclosing should not be capitalized, this is not a defined term in the NERC Glossary of terms.</li> <li>2. Section F: Although the SDT responded to Dominion's prior comments, Dominion believes that the SDT's response is deficient." in that Dominion does not support the inclusion of the phrase, "and that are located at and monitor quantities solely at the same station as the Element being switched or regulated." Why does it make a difference whether the controller is local or remote? The advent of high-speed phase measurement units (PMUs) and faster computer systems will eventually allow wide area control. This will become essential as the customer's load characteristic evolves (less voltage and frequency dependency means local PSSs will be less effective). We are concerned that the definition in general will hamper innovation. Right now there are schemes that control LTC's and capacitors to minimize losses. Certainly</li> </ol> |

| #  | Organization | Yes/<br>No | Question 1 Comment   |
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|  |              |            | <p>these are not RAS. There are EMS controls such as what PJM uses that dispatch generation pre-contingency to avoid overloads/voltage problems. These are not RAS either. Eventually computer EMS systems will become fast and robust enough to drop load or reconfigure the system so quickly that wide area blackouts will be virtually eliminated. Recall that only 500 MWs of load drop would have stopped the 2003 blackout. Therefore wide area systems that generically react to problems (not designed for a single specific contingency (if line A opens, do xyz action)) should not be RAS.</p> <p>3. Section N: Dominion does not agree with addition of (n) as written. The first paragraph of the definition states “A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation....So, to the extent automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, or speed governing is used in such a scheme it can’t be excluded. It may help clarify if the SDT expanded upon the intent of the phrase “The following do not individually constitute a RAS.”</p> <p>4. General comment: The elimination of SPS terminology , the move to one term- RAS and the addition of exclusion language only complicates the historical view on “special” schemes. This change will cause many US utilities burden due to references to SPS’s that will result in numerous revisions to existing compliance documentation, training programs, reference prints, and scheme application operating procedures. The majority of US utilities and at Protection Conferences the term SPS is used while the minority (most in WECC region) use the term RAS. Many times these schemes are made up primarily of protective relays to implement “special” applications. This change in definition is unnecessary and only introduces more questions when exclusions are introduced.</p> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team made the suggested change.</li> <li>2. The drafting team asserts that there are significant reliability risks associated with the PMU and EMS schemes you describe; consequently, these schemes are appropriately classified as RAS. The drafting team disagrees with the statement that RAS classification would hamper innovation. The difference between local and remote control is the associated increase of reliability risk. Schemes that act remotely are more likely to have a broad impact on the System and merit the more rigorous oversight required for RAS. For your examples: the drafting team agrees that schemes that control LTC’s and capacitors to minimize losses are typically not RAS; EMS controls for generation dispatch are typically not RAS; however, “wide area systems that generically react to problems” by dropping load or reconfiguring the System are typically RAS.</li> </ol> |              |            |  |

| #  | Organization     | Yes/<br>No | Question 1 Comment  |
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|    |                  |            | <p>3. The drafting team agrees that any of the excluded functions could be part of a larger scheme that could be a RAS. It appears that you understand this concept; consequently, the drafting team disagrees that the phrase “The following do not individually constitute a RAS” needs revision.</p> <p>4. The drafting team appreciates the fact that the selected term will cause some necessary documentation changes for entities but asserts that the use of the single term RAS will provide consistency and avoid the confusion associated with the SPS term. The drafting team acknowledges that entities will need time to adapt to the RAS term. The definition of RAS must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS. Note, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety. The existing definition of SPS/RAS also includes exclusions.</p>  |
| 18 | Peak Reliability | No         | <ol style="list-style-type: none"> <li>1. The new exclusion (n) that reads: “Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing” excludes certain historical RAS actions such as AGC blocking. It is agreed some generator controls like AVR and PSS are not RAS. See added inclusion list below.</li> <li>2. Adding BES to the possible objectives can be confusing to interpret. It can be interpreted that RAS are restricted to BES elements when that is not the intention of the standard. Peak recommends either removing “BES” from possible objectives or adding “(including sub-100 kV facilities identified as necessary by the Reliability Coordinator)” as shown below. Note this language is consistent with IRO-002-4 R3.</li> <li>3. It might be beneficial in the background information to include that RAS is distinctly different than industry standard (IEEE) definition for System Integrated Protection Scheme (SIPS).</li> <li>4. Proposed definition:<br/>             A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s).<br/>             RAS accomplish objectives such as:             <ul style="list-style-type: none"> <li>o Meet requirements identified in the NERC Reliability Standards;</li> <li>o Maintain Bulk Electric System (BES) (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) stability;</li> </ul> </li> </ol> |



| # | Organization | Yes/<br>No | Question 1 Comment   |
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|   |              |            | <ul style="list-style-type: none"> <li>○ Maintain acceptable BES (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) voltages;</li> <li>○ Maintain acceptable BES (including sub-100 kV facilities identified as necessary by the Reliability Coordinator) power flows;</li> <li>○ Limit the impact of Cascading or extreme events.</li> </ul> <p>The following constitute RAS:</p> <ul style="list-style-type: none"> <li>○ AGC blocking</li> <li>○ Fast valving</li> </ul> <p>The following do not individually constitute a RAS:</p> <ol style="list-style-type: none"> <li>a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements</li> <li>b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays</li> <li>c. Out-of-step tripping and power swing blocking.</li> <li>d. Automatic Reclosing schemes.</li> <li>e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service.</li> <li>f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated.</li> <li>g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device</li> <li>h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched</li> <li>i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open</li> <li>j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)</li> </ol> |

| #  | Organization   | Yes/<br>No | Question 1 Comment  |
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|  |  |            | <ul style="list-style-type: none"> <li>k. Automatic sequences that proceed when manually initiated solely by a System Operator</li> <li>l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations</li> <li>m. m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities(e.g., currents or torsional oscillations)</li> <li>n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing</li> </ul>           |
|  | <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team contends that AGC blocking by itself is not a RAS; however, it could be an integral part of a RAS.</li> <li>2. The definition of RAS does not necessarily exclude sub-100 kV facilities. Facilities that impact the BES can be subject to NERC jurisdiction. If an entity such as a Reliability Coordinator determines that sub-100kV facilities should be included in the BES, they can submit a request to the BES Exception Process for inclusion. The drafting team contends that the RAS definition and IRO-002-4 do not conflict with each other.</li> <li>3. Several IEEE papers define a similar term to SPS: System Integrity Protection System (SIPS). Adopting the SIPS definition is not appropriate because it is more inclusive than NERC’s definition: “The SIPS encompasses special protection system (SPS), remedial action schemes (RAS), as well as other system integrity schemes, such as underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc.” NERC applies special consideration to UF and UV load shedding schemes in the Reliability Standards and considers OOS relaying in the context of traditional protection systems. Thus, SIPS is not an appropriate term for use in the Reliability Standards, and a new definition of SPS is more appropriate.</li> </ol> |            |   |
| 19   | Consumers Energy Company   | No         | <p>The sentence originally read “RAS accomplish one or more of the following objectives:” This implies that it has to meet at least one of these criteria to be an applicable RAS. It was changed to read “RAS accomplish objectives such as:”</p> <p>This now implies that this is a just a list of examples but there may be other objectives that apply. I was relying on this original wording to limit the compliance exposure to BES systems only. The way it is written now it can be interpreted to apply to schemes on the non-BES system. Consumers Energy will vote negative on this ballot until this wording is changed back or some other way is used to limit this definition to only BES schemes.</p> |
| <p><b>Response:</b> Thank you for your comment. Regardless of the objective, schemes applied on non-BES systems that do not have a BES reliability impact would not be RAS; however, schemes applied on non-BES systems that do impact the BES reliability would be RAS.</p> |  |            |   |

| #  | Organization                | Yes/<br>No | Question 1 Comment  |
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| 20   | Tennessee Valley Authority  | No         | <ol style="list-style-type: none"> <li>1. We agree that using a single term should help bring the industry toward a common understanding/usage of the term. However, we disagree with the revised draft definition. Bullets 2-5 can be interpreted to cover objectives beyond NERC Reliability Standards, when taken in context with the first bullet. The scope of the definition should be limited to applications that are relevant to the NERC Reliability Standards in which the term is used.</li> <li>2. We think it's appropriate to address exclusions, however when the exclusion list is this long (and perhaps growing) it highlights the challenge in developing a good base definition for what constitutes a RAS NERC-wide. An alternative would be to "catalog" the RAS exclusions in a separate NERC reference document that could be revised without revising the base RAS definition.</li> <li>3. We feel that the implementation period should be extended to 5 years or more for existing schemes that are categorized as RAS by this definition change. Since the definition affects many additional standards, this could entail more work than anticipated to ensure full compliance with each one under the new definition.</li> </ol> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team disagrees. Schemes have been and may be applied for objectives beyond satisfying reliability standards. These schemes need similar review and oversight regarding design and implementation adequacy, coordination, misoperation, unintended consequences, etc. as schemes applied for satisfying Reliability Standards and therefore also need to be classified as RAS.</li> <li>2. Such a catalog would still be essential to determining RAS versus non-RAS and an additional document would be more cumbersome.</li> <li>3. The Implementation Plan already provides thirty-six (36) months from the time the definition is approved by an applicable governmental authority. The time is noted in the twelve (12) months leading up to the Effective Date of the standard plus the twenty four (24) months noted following the Effective Date. This only applies to existing schemes that must transition to RAS due to the revised definition. When the drafting team revises the RAS-related standards, those standards will include their own implementation periods. The drafting team agrees that a thorough review of all standards is prudent and asserts that the time period provided in the Implementation Plan is sufficient to evaluate existing compliance programs regarding the definition change.</li> </ol> |                             |            |   |
| 21   | Wisconsin Electric Power Co | No         | <p>We propose that the following changes be made to the list of exclusions:</p> <ol style="list-style-type: none"> <li>1. Item (e) - To "schemes applied to an Element for non-Fault conditions", add the following: over-excitation, over/under- frequency, motoring, load rejection, and unbalanced system conditions. We believe these are</li> </ol>  |

| #  | Organization | Yes/<br>No | Question 1 Comment  |
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|  |              |            | <p>abnormal, non-Fault system conditions for which protection is commonly applied, and should not be considered RAS.</p> <ol style="list-style-type: none"> <li>2. Item (n) Replace “Generator controls ...” with “Generator or turbine controls...”</li> <li>3. Add a new exclusion for protective functions for black start generators that may be implemented to allow greater than normal voltage or frequency tolerance during restoration conditions.</li> </ol>  |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. While we agree that the examples you provide would not individually be considered RAS, the drafting team did not intend to develop an all-inclusive list of examples in each of the exclusions.</li> <li>2. The drafting team contends that Generator controls includes turbine controls, and declines to make the suggested change.</li> <li>3. During system restoration, the System Operators are manually controlling the black start of generators which falls outside the definition of RAS. By definition, RAS automatically take corrective actions.</li> </ol> |              |            |   |
| 22   | WAPA         | No         | <p>Western requests the SDT re-consider an additional exclusion for “cross-tripping schemes within the same station”. We continue to believe such a simplistic localized hard-wired scheme should be outside the purview of a RAS and its associated scrutiny and approval, which particularly does not lend itself to the operating horizon. By and large, implementation of a cross-trip within the same station is utilized to mitigate a thermal SOL by tripping another element in lieu of the overloaded element. Not only does this action mitigate an SOL, it most often improves the robustness and reliability of the remaining BES system to deliver firm commitments. Without such exclusion, the SOL element often must be opened pre-contingent, thus further degrading the robustness of the BES. The proposed exceptions are appropriate; however, they are still inadequate. The end effect of the proposed RAS definition basically captures any protection action and/or scheme that is beyond standard/historical individual relaying protection package functions, thereby limiting the ‘art’ of system protection to ‘maximize the robustness of the post-contingent BES system’. On this basis, Western suggests the SDT reconsider the definition’s strict inclusion of “reconfiguring a System(s)”. Western’s suggestion of excluding “cross-tripping schemes within the same station” for sake of mitigating a potential SOL is more benign should it fail to operate than failure of the currently proposed exclusion of “out-of-step tripping and power swing blocking”, as an example. Did the last SPS definition’s use of the language “acceptable voltage, or power flow” intend to capture the granularity of localized SOLs versus larger and/or regional BES impacts? Further, the definition does not delineate lower risk “localized” schemes. Consequently, there is no expeditious approval mechanism to implement a benign localized scheme within a reasonable timeframe for the operating horizon. This is a real issue. Several years ago following spring flooding, Western had</p> |

| #   | Organization | Yes/<br>No | Question 1 Comment  |
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|   |              |            | <p>transmission lines toppling in standing water and needed to quickly implement a cross-trip scheme to facilitate needed and urgent outages for maintenance/repair (within days). Without such flexibility, customer service and reliability is further reduced. Western suggests the SDT recognize “localized” benign schemes either outside the scrutiny of a RAS all together, or at minimum, allow such schemes to be implemented for 1 year with the caveat that the scheme be vetted through an expedited stakeholder process. If the “localized” scheme ultimately must receive RAS review and scrutiny, it should be done expeditiously. Currently, the WECC RASRS are attempting to streamline “localized’ schemes.</p>   |
| <p><b>Response:</b> Thank you for your comments. The drafting team contends that performing switching in the same substation (including transfer or cross-trip schemes) that trip Elements other than the protected Element is a System reconfiguration and is therefore a RAS. Reconfiguring the System can be a critical factor in reliability and merits the review and oversight associated with RAS. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS; therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. Comments received from the informal comment period were valuable during the drafting team’s deliberations and are publicly available on the project’s web page. The proposed definition was posted for formal comment and ballot following revisions made based in-part on stakeholder input. This issue will be addressed by the RAS classification during the standards development phase of the project in 2015. Similarly, RAS review will be addressed during the standards development phase of the project.</p> |              |            |   |
| 23  | PacifiCorp   | No         | <p>Western requests the SDT to re-consider an additional exclusion for “cross-tripping schemes within the same station”. We continue to believe such a simplistic localized scheme should be outside the purview of a RAS and its associated scrutiny and approval, which particularly does not lend itself to the operating horizon. By and large, implementation of a cross-trip within the same station is utilized to mitigate a thermal SOL by tripping another element in lieu of the overloaded element. Not only does this action mitigate a thermal SOL, it most often improves the robustness and reliability of the remaining BES system to deliver firm commitments.</p> <p>The proposed exceptions are appropriate; however, they are still inadequate. The end effect of the proposed RAS definition includes any protection action and/or scheme that is beyond standard/historical individual relaying protection package functions, thereby limiting the ‘art’ of system protection to include the objective of ‘maximizing the robustness of the remaining BES system’. On this basis, Western suggests the SDT reconsider the definition strictly including “reconfiguring a System(s)”.</p> |

| #  | Organization                            | Yes/<br>No | Question 1 Comment   |
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|  |   |            | <p>The suggestion of excluding “cross-tripping schemes within the same station” for sake of mitigating a potential thermal overload is more benign should it fail to operate than failure of the currently proposed exclusion of “out-of-step tripping and power swing blocking”, as an example.</p> <p>Further, the definition does not delineate lower risk “localized” schemes. Consequently, there is no expeditious avenue to implement a localized benign scheme within a reasonable timeframe for the operating horizon. This is a real issue. As example, following the flood of 2011, Western had transmission lines toppling in standing water and needed to quickly implement a cross-trip scheme to facilitate needed and urgent outages for maintenance/repair (within days). Western suggests the SDT recognize “localized” benign schemes either outside the scrutiny of a RAS all together, or at minimum, allow such schemes to be implemented for 1 year with the caveat that the scheme be vetted through an expedited stakeholder process. If the “localized” scheme ultimately must receive RAS review and scrutiny, it should be done expeditiously. Currently, the WECC RASRS attempts to streamline “localized’ schemes.</p> |
| <p><b>Response:</b> Thank you for your comments. The drafting team contends that performing switching in the same substation (including transfer- or cross-trip schemes) that trip Elements other than the protected Element is a System reconfiguration and is therefore a RAS. Reconfiguring the System can be a critical factor in reliability and merits the review and oversight associated with RAS. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS; therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. Comments received from the informal comment period were valuable during the drafting team’s deliberations and are publicly available on the project’s web page. The proposed definition was posted for formal comment and ballot following revisions made based in-part on stakeholder input. This issue will be addressed by the RAS classification during the standards development phase of the project in 2015. Similarly, RAS review will be addressed during the standards development phase of the project.</p> |   |            |  |
| 24   | Florida<br>Municipal<br>Power<br>Agency | Yes        | <p>FMPA agrees with the changes to the definition of Remedial Action Scheme but maintains that a thorough review of all standards should be conducted to look for uses of the terms Protection System(s) and protection system(s) to determine if it was intended to include SPS/RAS as part of the requirement. Simply removing the statement “These schemes are not Protection Systems; however, they may share components with Protection Systems” does not accomplish the same objective. As an example, PER-005-1 R3.1 may or may not be interpreted to include Remedial Actions Schemes.</p>   |
| <p><b>Response:</b> Thank you for your comment. The drafting team will conduct a review as part of the standards development process.</p>  |   |            |  |

| #  | Organization                       | Yes/<br>No | Question 1 Comment   |
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| 25   | American Transmission Company, LLC | Yes        | However, ATC suggests the addition of parenthetical verbiage similar to today’s SPS definition to exclusion (c). The suggested change to exclusion (c) would read “Out-of-step tripping and power swing blocking (not designed as an integral part of an RAS).”  |
| <p><b>Response:</b> Thank you for your comment. The drafting team contends the existing sentence “The following do not individually constitute a RAS” accomplishes what you are requesting and declines to make the suggested change.</p>  |                                    |            |  |
| 26   | Ingleside Cogeneration LP          | Yes        | Ingleside Cogeneration LP (ICLP) agrees that the latest version of the RAS definition is a distinct improvement over its predecessor. The removal of the catch-all inclusion for schemes that address “other Bulk Electric System (BES) reliability concerns” is the primary reason for our “Yes” vote this time around. With it, the definition inferred that every automated system that has even the most tenuous tie to reliability could be considered as RAS - which clearly is not the intent of this initiative. Another positive modification in our view is the new exclusion for generator control systems like AGC, PSS, AVR’s, and governors. These clearly are not Remedial Action Schemes, but without the exclusion it is possible to construe them as such. While not affecting our vote, ICLP would like a better explanation to the elimination of categories of RAS - as originally recommended by the SPCS. The only response we saw was a statement that “informal feedback from many stakeholders” led to this decision. Perhaps there are very good reasons they were only shared with the project team, but the Standards Development Process is expected to be open and deliberative. The informal process is important in order to stimulate good ideas and discussion, but should not play a part in the review/ballot unless it is documented and vetted by all participating stakeholders. |
| <p><b>Response:</b> Thank you for your comment. The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS; therefore, the drafting team decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards. Comments received from the informal comment period were valuable during the drafting team’s deliberations and are publicly available on the project’s web page. The proposed definition was posted for formal comment and ballot following revisions made based in-part on stakeholder input.</p> |                                    |            |  |
| 27   | PNM Resources Inc.                 | Yes        | PNM Resources appreciates the work of the Drafting team and would request that there be a clarification that 'Temporary Outage Action Plans' or 'TOAPs' (used in the TRE/ERCOT area) are not included in the definition of RAS.<br><br>It appears that TOAPs used by ERCOT entities would primarily be subject to ‘Exclusion E’ as they are temporary schemes that would switch elements based on voltage or to avoid thermal overload on non-faulted elements.  |

| #  | Organization               | Yes/No | Question 1 Comment  |
|--|----------------------------|--------|---|
|  |                            |        | They could additionally fall under 'Exclusion K' and would take the action that would normally be executed by System Operators manually. TOAPs are developed to protect against a temporary condition that could arise during a planned maintenance outage which are utilized widely in the TRE/ERCOT area and in PNM Resources' opinion should not be considered RAS which would then require that any Temporary Outage Action Plan would trigger CIP-002-5 inclusion of a BES asset to evaluate and have to apply CIP protections to systems not typically included in CIP scope. |
| <p><b>Response:</b> Thank you for your comment. The drafting team asserts that the 'temporary' status is not relevant in the definition of RAS. Without detailed information, the drafting team cannot determine whether or not specific schemes (TOAPs) would be RAS or fall under any of the exclusions.</p> |                            |        |   |
| 28   | SPP Standards Review Group | Yes    | We appreciate the effort of the drafting team in developing the proposed revised definition. The new revision is much clearer. The expansion of the list of exclusions has been a big help. Whenever the NERC Glossary of Terms is referenced in the standard and in the Background and FAQ document, the full name is used - Glossary of Terms Used in NERC Reliability Standards. This is the case with one exception, in the 1st line of the answer to the 1st question under the FAQ section of the Background and FAQ document. Please make the appropriate change here.       |
| <p><b>Response:</b> Thank you for your comment. The drafting team made the suggested change.</p>   |                            |        |   |
| 29   | Exelon Companies           | Yes    | We think the following should be considered. Exclusion "e" specifically includes "transformer top-oil temperature". Other common transformer protection such as "winding temperature" and "loss of cooling" measure distinctly different parameters from top oil temperature but share a similar goal. These protection schemes seem conspicuous by their absence from exclusion "e". They are arguably covered under the "but not limited to" clause but especially the former seems common enough that it merits specific mention.  |
| <p><b>Response:</b> Thank you for your comment. While we agree that the examples you provide would not individually be considered RAS, the drafting team did not intend to develop an all-inclusive list of examples in each of the exclusions.</p>  |                            |        |   |
| 30   | Xcel Energy                | Yes    | While Xcel Energy agrees with the revised definition, we offer the comments below for the Drafting Team's consideration:<br>We observe that the proposed new RAS definition is substantively and structurally very similar to the existing SPS/RAS definition. The most significant change in the proposed new definition is the detailed list of 14 exclusions versus the 3 exclusions in the existing definition - we agree that the additional exclusions are a useful enhancement.  |



| #  | Organization            | Yes/<br>No | Question 1 Comment  |
|--|-------------------------|------------|---|
|  |                         |            | <p>However, the functional description of RAS characterized by its purpose and actions is almost the same in both definitions - we note that the first sentence in both definitions contains identical verbiage “designed to detect predetermined System conditions and (automatically) take corrective actions...”. In the new definition, this is followed by a listing of typical corrective actions before stating the reliability objectives in the second sentence - whereas the existing definition enumerates them both in the second sentence. However, the three examples provided for corrective actions and objectives are common to both definitions, and are supplemented with two additional reliability objectives in the proposed new definition.</p> <p>Given these substantive commonalities, we recommend that the proposed new definition be restructured as follows to make it easier to discern the similarities retained and the enhancements introduced relative to the existing definition, as well as improve its contextual clarity and readability.</p> <p>[A scheme designed to detect predetermined System conditions and automatically take corrective actions &lt;to&gt; accomplish &lt;BES reliability&gt; objectives such as:</p> <ul style="list-style-type: none"> <li>(1) Meet requirements identified in the NERC Reliability Standards</li> <li>(2) Maintain Bulk Electric System (BES) stability</li> <li>(3) Maintain acceptable BES voltages</li> <li>(4) Maintain acceptable BES power flows</li> <li>(5) Limit the impact of Cascading or extreme events.</li> </ul> <p>Corrective actions may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring System(s).]</p> <p>Irrespective of whether the proposed restructuring of the definition is implemented or not, we suggest that the reliability objectives be re-sequenced. Due to the non-specific “catch-all” nature of the first objective (meet requirements in reliability standards), we recommend that it be listed as the last objective to follow the four specific attributes of reliable system performance.</p> |
| <p><b>Response:</b> Thank you for your comment. The drafting team appreciates the suggestion but declines to make the changes.</p> |                         |            |   |
| 31   | American Electric Power | Yes        | <p>1. Within the section “The following do not individually constitute a RAS”, AEP recommends the following changes: Item a: Delete “BES” so that it reads “Protection Systems installed for the purpose of detecting Faults on Elements and isolating the faulted Elements”.</p>   |

| #  | Organization  | Yes/<br>No | Question 1 Comment   |
|--|---|------------|--|
|  |   |            | <p>2. Item e: Add the qualifier “reverse power” so that it reads “Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, reverse power, or overload to protect the Element against damage by removing it from service.”</p> <p>3. Item k: Delete the phrase “that proceed when” and add the text “that proceeds directly to a desired system state” so that it reads “Automatic sequences manually initiated solely by a System Operator that proceeds directly to a desired system state.”</p> |
| <p><b>Response:</b> Thank you for your comments.</p> <ol style="list-style-type: none"> <li>1. The drafting team agreed that Protection Systems installed for the purpose of detecting Faults on non-BES Elements do not meet the definition of RAS, and thus are not subject to the RAS-related NERC Reliability Standards. The drafting team did not remove the BES modifier.</li> <li>2. While we agree that the example you provide would not individually be considered RAS, the drafting team did not intend to develop an all-inclusive list of examples in each of the exclusions. The drafting team agrees that a reverse power relay by itself would not constitute a RAS.</li> <li>3. Please see the ‘Exclusion List Explanations’ in the FAQ regarding Exclusion ‘k’. No change made to the definition.</li> </ol> |   |            |  |
| 32   | Arizona Public Service Co   | Yes        |  |
| 33   | Southern Company; Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power | Yes        |  |

| #  | Organization   | Yes/<br>No | Question 1 Comment |
|----|--|------------|--------------------|
|    | Company;<br>Mississippi<br>Power<br>Company;<br>Southern<br>Company<br>Generation;<br>Southern<br>Company<br>Generation<br>and Energy<br>Marketing |            |                    |
| 34 | Pepco<br>Holdings Inc  | Yes        |                    |
| 35 | Independent<br>Electricity<br>System<br>Operator   | Yes        |                    |
| 36 | Idaho Power  | Yes        |                    |
| 37 | South<br>Carolina<br>Electric &<br>Gas Co.   | Yes        |                    |
| 38 | Oncor<br>Electric<br>Delivery LLC  | Yes        |                    |
| 39 | PJM<br>Interconnecti<br>on   | Yes        |                    |

| #  | Organization   | Yes/No | Question 1 Comment |
|----|----------------|--------|--------------------|
| 40 | Manitoba Hydro | Yes    |                    |

**Additional Comments:**

**Associated Electric Cooperative, Inc.  
Phil Hart**

**1. No**

**Comments:**

The purpose of this project is stated as, "...assist the industry with the application of the revised definition." However the current revision seems to be providing more confusion than clarity. Because both the Inclusions and Exclusions are so broad, it would seem everything is first included in a RAS, and then excluded, leaving nothing. AECI would suggest the SDT at least limit such broad inclusions to begin with, and in turn this would require fewer exclusions on the back-end.

**Response:** Thank you for your comment. The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS. Note, if a scheme or protective system is not explicitly defined as an exclusion, it is not by default a RAS - the definition of RAS must be met in its entirety.

**END OF REPORT**

## Proposed Definition of “Remedial Action Scheme”

### *Remedial Action Scheme (RAS)*

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Existing Definitions – Glossary of Terms Used in NERC Reliability Standards

### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

### *Remedial Action Scheme*

See “Special Protection System”

## Proposed Definition of “Remedial Action Scheme”

### *Remedial Action Scheme (RAS)*

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic R~~r~~eclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Existing Definitions – Glossary of Terms Used in NERC Reliability Standards

### *Special Protection System (Remedial Action Scheme)*

An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

### *Remedial Action Scheme*

See “Special Protection System”



# Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## Project 2010-05.2 – Special Protection Systems

### Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: “An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.”

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

### Requested Approvals

Definition of “**Remedial Action Scheme**” and the standards listed below

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of “Remedial Action Scheme” becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

|                 |                |                |
|-----------------|----------------|----------------|
| CIP-002-3(i)    | PRC-004-WECC-2 | PRC-020-2      |
| CIP-002-3(ii)b  | PRC-005-2(ii)  | PRC-021-2      |
| EOP-004-3       | PRC-005-3(ii)  | PRC-023-2(i)   |
| FAC-010-3       | PRC-006-1(i)   | PRC-023-4      |
| FAC-011-3       | PRC-012-1      | TOP-005-3a     |
| IRO-005-3.1(i)a | PRC-013-1      | TPL-001-0.1(i) |
| MOD-029-2a      | PRC-014-1      | TPL-002-0(i)b  |
| MOD-030-3       | PRC-015-1      | TPL-003-0(i)b  |
| NUC-001-2.1(i)  | PRC-016-1      | TPL-004-0(i)a  |
| PRC-001-1.1(i)  | PRC-017-1      |                |

### Requested Retirements

|              |                |             |
|--------------|----------------|-------------|
| CIP-002-3    | PRC-004-WECC-1 | PRC-020-1   |
| CIP-002-3b   | PRC-005-2      | PRC-021-1   |
| EOP-004-2    | PRC-005-3      | PRC-023-2   |
| FAC-010-2.1  | PRC-006-1      | PRC-023-3   |
| FAC-011-2    | PRC-012-0      | TOP-005-2a  |
| IRO-005-3.1a | PRC-013-0      | TPL-001-0.1 |
| MOD-029-1a   | PRC-014-0      | TPL-002-0b  |
| MOD-030-02   | PRC-015-0      | TPL-003-0b  |
| NUC-001-2.1  | PRC-016-0.1    | TPL-004-0a  |
| PRC-001-1.1  | PRC-017-0      |             |

### General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

### **Prerequisite Approvals**

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding  
Definition of “Undervoltage Load Shedding Program (UVLS Program)” in Project 2008-02 Undervoltage Load Shedding

### **Revisions to the NERC Glossary of Terms**

The drafting team proposes the following revised definition:

#### **Remedial Action Scheme (RAS)**

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

### **Conforming Changes to Other Standards**

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

### **Effective Date for Revised Reliability Standards and Definition**

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### **Implementation Plan for Newly Classified Remedial Action Schemes (RAS)**

Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

**Retirement of Existing Standards and Definitions**

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of “Remedial Action Scheme” shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of “Remedial Action Scheme”.

# Implementation Plan for the Revised Definition of “Remedial Action Scheme”

## Project 2010-05.2 – Special Protection Systems

### Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: “An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.”

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

### Requested Approvals

Definition of “**Remedial Action Scheme**” and the standards listed below

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of “Remedial Action Scheme” becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

|                 |                |                |
|-----------------|----------------|----------------|
| CIP-002-3(i)    | PRC-004-WECC-2 | PRC-020-2      |
| CIP-002-3(ii)b  | PRC-005-2(ii)  | PRC-021-2      |
| EOP-004-3       | PRC-005-3(ii)  | PRC-023-2(i)   |
| FAC-010-3       | PRC-006-1(i)   | PRC-023-4      |
| FAC-011-3       | PRC-012-1      | TOP-005-3a     |
| IRO-005-3.1(i)a | PRC-013-1      | TPL-001-0.1(i) |
| MOD-029-2a      | PRC-014-1      | TPL-002-0(i)b  |
| MOD-030-3       | PRC-015-1      | TPL-003-0(i)b  |
| NUC-001-2.1(i)  | PRC-016-1      | TPL-004-0(i)a  |
| PRC-001-1.1(i)  | PRC-017-1      |                |

### Requested Retirements

|              |                |             |
|--------------|----------------|-------------|
| CIP-002-3    | PRC-004-WECC-1 | PRC-020-1   |
| CIP-002-3b   | PRC-005-2      | PRC-021-1   |
| EOP-004-2    | PRC-005-3      | PRC-023-2   |
| FAC-010-2.1  | PRC-006-1      | PRC-023-3   |
| FAC-011-2    | PRC-012-0      | TOP-005-2a  |
| IRO-005-3.1a | PRC-013-0      | TPL-001-0.1 |
| MOD-029-1a   | PRC-014-0      | TPL-002-0b  |
| MOD-030-02   | PRC-015-0      | TPL-003-0b  |
| NUC-001-2.1  | PRC-016-0.1    | TPL-004-0a  |
| PRC-001-1.1  | PRC-017-0      |             |

### General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

### **Prerequisite Approvals**

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding  
Definition of “Undervoltage Load Shedding Program (UVLS Program)” in Project 2008-02 Undervoltage Load Shedding

### **Revisions to the NERC Glossary of Terms**

The drafting team proposes the following revised definition:

#### **Remedial Action Scheme (RAS)**

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated



- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

### Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

### Effective Date for Revised Reliability Standards and Definition

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

### Implementation Plan for Newly ~~Identified-Classified~~ Remedial Action Schemes (RAS)

Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24) months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

**Retirement of Existing Standards and Definitions**

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of “Remedial Action Scheme” shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of “Remedial Action Scheme”.

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(i)
3. **Purpose:** NERC Standards CIP-002-3(i) through CIP-009-3(i) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(i) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**
  - 4.1. Within the text of Standard CIP-002-3(i), “Responsible Entity” shall mean:
    - 4.1.1 Reliability Coordinator.
    - 4.1.2 Balancing Authority.
    - 4.1.3 Interchange Authority.
    - 4.1.4 Transmission Service Provider.
    - 4.1.5 Transmission Owner.
    - 4.1.6 Transmission Operator.
    - 4.1.7 Generator Owner.
    - 4.1.8 Generator Operator.
    - 4.1.9 Load Serving Entity.
    - 4.1.10 NERC.
    - 4.1.11 Regional Entity.
  - 4.2. The following are exempt from Standard CIP-002-3(i):
    - 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
    - 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

**B. Requirements**

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
  - R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
  - R1.2.** The risk-based assessment shall consider the following assets:
    - R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
    - R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
    - R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
    - R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
    - R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
    - R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
    - R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(i), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
  - R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
  - R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
  - R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of

the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(i) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

- 1.5.1** None.

**2. Violation Severity Levels (To be developed later.)**

**E. Regional Variances**

None identified.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------------|---|--|
| 1              | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2              |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3              |                   | Updated version number from -2 to -3  |  |
| 3              | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
| 3(i)           | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(i)
3. **Purpose:** NERC Standards CIP-002-3(i) through CIP-009-3(i) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(i) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3(i), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3(i):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

## B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(i), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of



the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(i) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

- 1.5.1** None.

**2. Violation Severity Levels (To be developed later.)**

**E. Regional Variances**

None identified.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2       |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3       |                   | Updated version number from -2 to -3  |  |
| 3       | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
| 3(i)    | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(i)b
3. **Purpose:** NERC Standards CIP-002-3(i)b through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(i)b requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**
  - 4.1. Within the text of Standard CIP-002-3(i)b, “Responsible Entity” shall mean:
    - 4.1.1 Reliability Coordinator.
    - 4.1.2 Balancing Authority.
    - 4.1.3 Interchange Authority.
    - 4.1.4 Transmission Service Provider.
    - 4.1.5 Transmission Owner.
    - 4.1.6 Transmission Operator.
    - 4.1.7 Generator Owner.
    - 4.1.8 Generator Operator.
    - 4.1.9 Load Serving Entity.
    - 4.1.10 NERC.
    - 4.1.11 Regional Entity.
  - 4.2. The following are exempt from Standard CIP-002-3(i)b:
    - 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
    - 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

**B. Requirements**

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
  - R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
  - R1.2.** The risk-based assessment shall consider the following assets:
    - R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
    - R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
    - R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
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    - R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
    - R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
    - R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
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  - R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
  - R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
  - R3.3.** The Cyber Asset is dial-up accessible.

- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

Compliance Audits  
Self-Certifications  
Spot Checking  
Compliance Violation Investigations  
Self-Reporting  
Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(i)b from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

**1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

**1.5.1** None.

2. Violation Severity Levels

| Requirement | VRF    | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-------------|--------|-----------|---|---|--|
| R1.         | MEDIUM | N/A       | N/A   | N/A   | The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.                 |
| R1.1.       | LOWER  | N/A       | The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures. | The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria. | The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria. |
| R1.2.       | MEDIUM | N/A       | N/A   | N/A   | The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.                             |
| R1.2.1.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.2.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.3.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.4.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.5.     | LOWER  | N/A       | N/A   | N/A   | N/A  |

**Standard CIP-002-3(i)b — Cyber Security — Critical Cyber Asset Identification**

| Requirement | VRF   | Lower VSL | Moderate VSL  | High VSL   | Severe VSL   |
|-------------|-------|-----------|---|--|--|
| R1.2.6.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R1.2.7.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R2.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.  | The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.   |
| R3.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required. | The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null. |
| R3.1.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.2.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.3.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R4.         | LOWER | N/A       | The Responsible Entity does not have a signed and dated | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual   | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of   |



**Standard CIP-002-3(i)b — Cyber Security — Critical Cyber Asset Identification**

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| Requirement | VRF | Lower VSL | Moderate VSL   | High VSL   | Severe VSL  |
|-------------|-----|-----------|--|--|---|
|             |     |           | record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets <b>or</b> the list of Critical Cyber Assets (even if such lists are null.) | approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.) | 1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.) |

**E. Regional Variances**

None identified.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2       |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3       |                   | Updated version number from -2 to -3  |  |
| 3       | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
| 3a      | May 9, 2012       | Interpretation of R3 for Duke Energy adopted by the NERC Board of Trustees  |  |
| 3b      | February 7, 2013  | Interpretation of R1.2.5 for OGE adopted by the NERC Board of Trustees  |  |
| 3b      | March 21, 2013    | FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)  |  |
| 3(i)b   | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Appendix 1**

**Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation**

Date submitted: 2/24/11

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

**Requirement Number and Text of Requirement**

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

**Identify specifically what requirement needs clarification (as submitted):**

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

### **Question Summary**

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

### **Response**

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

**A. Introduction**

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(i)b
3. **Purpose:** NERC Standards CIP-002-3(i)b through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(i)b requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

**4. Applicability:**

**4.1.** Within the text of Standard CIP-002-3(i)b, “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

**4.2.** The following are exempt from Standard CIP-002-3(i)b:

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

## B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(i)b, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.

- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

**C. Measures**

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

**1.3. Compliance Monitoring and Enforcement Processes**

Compliance Audits  
Self-Certifications  
Spot Checking  
Compliance Violation Investigations  
Self-Reporting  
Complaints

**1.4. Data Retention**

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(i)b from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

**1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

**1.5. Additional Compliance Information**

**1.5.1** None.



2. Violation Severity Levels

| Requirement | VRF    | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-------------|--------|-----------|---|---|--|
| R1.         | MEDIUM | N/A       | N/A   | N/A   | The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.                 |
| R1.1.       | LOWER  | N/A       | The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures. | The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria. | The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria. |
| R1.2.       | MEDIUM | N/A       | N/A   | N/A   | The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.                             |
| R1.2.1.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.2.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.3.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.4.     | LOWER  | N/A       | N/A   | N/A   | N/A  |
| R1.2.5.     | LOWER  | N/A       | N/A   | N/A   | N/A  |

**Standard CIP-002-3(i)b — Cyber Security — Critical Cyber Asset Identification**

| Requirement | VRF   | Lower VSL | Moderate VSL  | High VSL   | Severe VSL   |
|-------------|-------|-----------|---|--|--|
| R1.2.6.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R1.2.7.     | LOWER | N/A       | N/A   | N/A  | N/A  |
| R2.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.  | The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.   |
| R3.         | HIGH  | N/A       | N/A   | The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required. | The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null. |
| R3.1.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.2.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R3.3.       | LOWER | N/A       | N/A   | N/A  | A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.           |
| R4.         | LOWER | N/A       | The Responsible Entity does not have a signed and dated | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual   | The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of   |

**Standard CIP-002-3(i)b — Cyber Security — Critical Cyber Asset Identification**

| Requirement | VRF | Lower VSL | Moderate VSL   | High VSL   | Severe VSL  |
|-------------|-----|-----------|--|--|---|
|             |     |           | record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets <b>or</b> the list of Critical Cyber Assets (even if such lists are null.) | approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.) | 1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.) |

**E. Regional Variances**

None identified.

**Version History**

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 1       | January 16, 2006  | R3.2 — Change “Control Center” to “control center”  | Errata   |
| 2       |                   | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a responsible entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. |  |
| 3       |                   | Updated version number from -2 to -3  |  |
| 3       | December 16, 2009 | Approved by the NERC Board of Trustees  | Update   |
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| 3b      | March 21, 2013    | FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)  |  |
| 3(i)b   | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Appendix 1

**Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation**

Date submitted: 2/24/11

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

**Requirement Number and Text of Requirement**

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

**Identify specifically what requirement needs clarification (as submitted):**

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

### **Question Summary**

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

### **Response**

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

### A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2-3
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider

### 5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

### 6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### **B. Requirements and Measures**

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2-3 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
  
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2-3 Attachment 1 and in accordance with the entity responsible for reporting.
  
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
  
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2-3 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the



end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

### C. Compliance

#### 1. Compliance Monitoring Process

##### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

##### 1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

**1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None

Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br><br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |

| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)

**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |

**EOP-004-2-3 — Event Reporting**

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq 100$ MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq 100$ MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm 10\%$ of nominal voltage sustained for $\geq 15$ continuous minutes.  |

**EOP-004-2-3 — Event Reporting**

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |



**EOP-004-2-3 — Event Reporting**

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| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |

EOP-004 - Attachment 2: Event Reporting Form

| <b>EOP-004 Attachment 2: Event Reporting Form</b>   |  |
|---|--|
| <p><b>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a> , Facsimile 404-446-9770 or voice: 404-446-9780.</b></p>  |  |
| Task  | Comments   |
| 1.  | Entity filing the report include:<br>Company name:<br>Name of contact person:<br>Email address of contact person:<br>Telephone Number:<br>Submitted by (name): |
| 2.  | Date and Time of recognized event.<br>Date: (mm/dd/yyyy)<br>Time: (hh:mm)<br>Time/Zone:  |
| 3.  | Did the event originate in your system?      Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/>                         |
| 4.  | <b>Event Identification and Description:</b>   |
| (Check applicable box)<br><input type="checkbox"/> Damage or destruction of a Facility<br><input type="checkbox"/> Physical Threat to a Facility<br><input type="checkbox"/> Physical Threat to a control center<br><input type="checkbox"/> BES Emergency:<br><input type="checkbox"/> public appeal for load reduction<br><input type="checkbox"/> system-wide voltage reduction<br><input type="checkbox"/> manual firm load shedding<br><input type="checkbox"/> automatic firm load shedding<br><input type="checkbox"/> Voltage deviation on a Facility<br><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)<br><input type="checkbox"/> Loss of firm load<br><input type="checkbox"/> System separation<br><input type="checkbox"/> Generation loss<br><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)<br><input type="checkbox"/> Transmission loss<br><input type="checkbox"/> unplanned control center evacuation<br><input type="checkbox"/> Complete loss of voice communication capability<br><input type="checkbox"/> Complete loss of monitoring capability | Written description (optional):  |

### Guideline and Technical Basis

#### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

#### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

#### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### **Data Gathering**

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### **Law Enforcement Reporting**

The reliability objective of EOP-004-2-3 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### **Stakeholders in the Reporting Process**

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

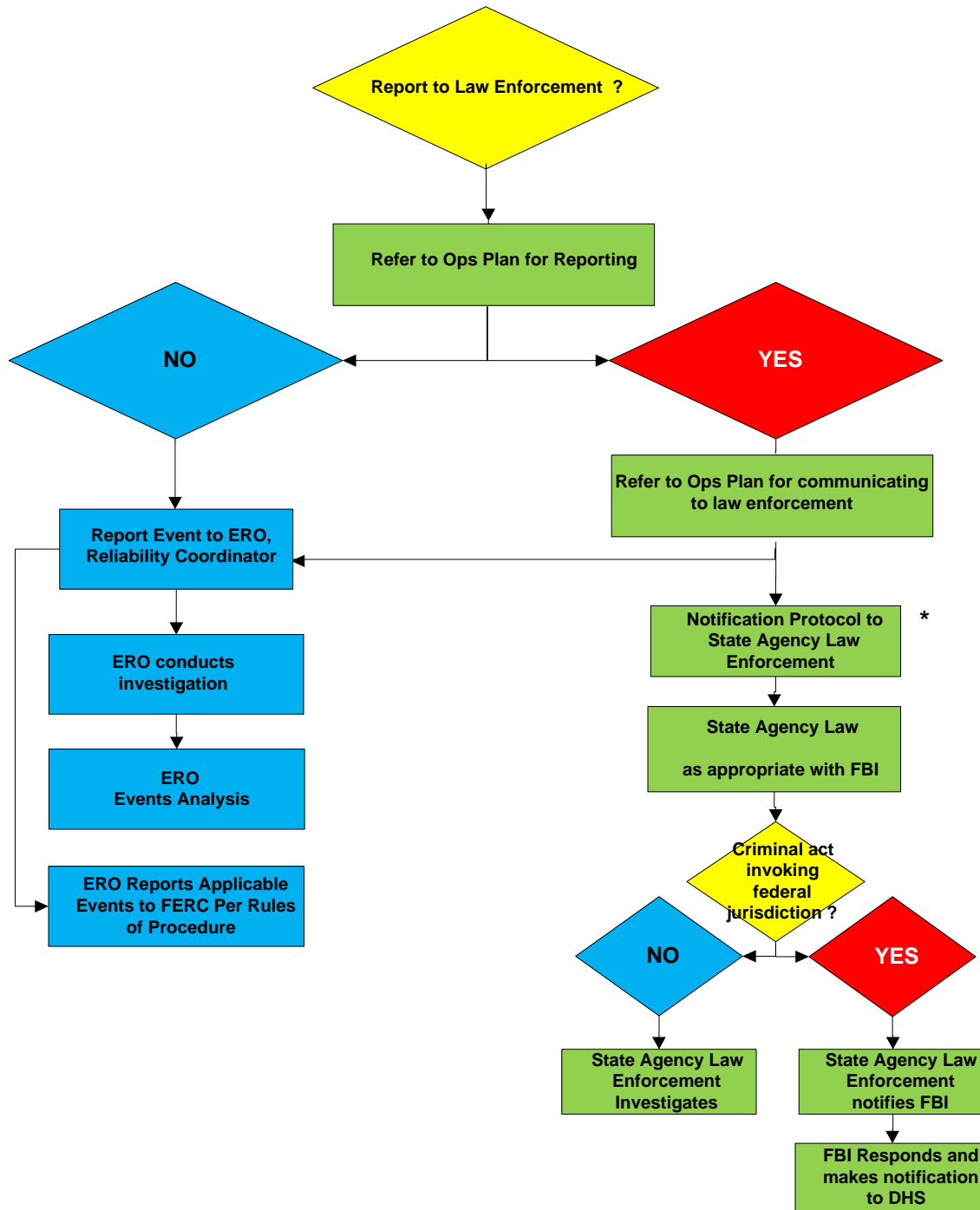
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

### **Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts**

#### **Introduction**

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

#### **Summary of Concepts and Assumptions:**

##### ***The Standard:***

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

##### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.



3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### **Discussion of Event Reporting**

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### ***What about sabotage?***

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2-3 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

## Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 2       |                  | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)  |
| 2       | November 7, 2012 | Adopted by the NERC Board of Trustees  |  |
| 2       | June 20, 2013    | FERC approved  |  |
| 2-3     | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2-3
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
  - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
    - 4.1.1. Reliability Coordinator
    - 4.1.2. Balancing Authority
    - 4.1.3. Transmission Owner
    - 4.1.4. Transmission Operator
    - 4.1.5. Generator Owner
    - 4.1.6. Generator Operator
    - 4.1.7. Distribution Provider

### 5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

### 6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

### B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2-3 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2-3 Attachment 1 and in accordance with the entity responsible for reporting.
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2-3 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

#### 1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

**1.3 Compliance Monitoring and Enforcement Processes:**

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

**1.4 Additional Compliance Information**

None



Table of Compliance Elements

| R # | Time Horizon        | VRF   | Violation Severity Levels  |   |   |  |
|-----|---------------------|-------|--|---|---|--|
|     |                     |       | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
| R1  | Operations Planning | Lower | The Responsible Entity had an Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types.<br><br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |

| R # | Time Horizon          | VRF    | Violation Severity Levels   |   |   |   |
|-----|-----------------------|--------|---|---|---|---|
|     |                       |        | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
| R2  | Operations Assessment | Medium | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p> | <p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p> |

| R # | Time Horizon        | VRF    | Violation Severity Levels  |   |  |  |
|-----|---------------------|--------|--|---|--|--|
|     |                     |        | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
| R3  | Operations Planning | Medium | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p> | <p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p> |

**D. Variances**

None.

**E. Interpretations**

None.

**F. References**

Guideline and Technical Basis (attached)

**EOP-004 - Attachment 1: Reportable Events**

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: [systemawareness@nerc.net](mailto:systemawareness@nerc.net), Facsimile 404-446-9770 or Voice: 404-446-9780.

**Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.**

| Event Type                          | Entity with Reporting Responsibility | Threshold for Reporting   |
|-------------------------------------|--------------------------------------|---|
| Damage or destruction of a Facility | RC, BA, TOP                          | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.   |
| Damage or destruction of a Facility | BA, TO, TOP, GO, GOP, DP             | Damage or destruction of its Facility that results from actual or suspected intentional human action.   |
| Physical threats to a Facility      | BA, TO, TOP, GO, GOP, DP             | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at a Facility.<br>Do not report theft unless it degrades normal operation of a Facility. |

| Event Type   | Entity with Reporting Responsibility           | Threshold for Reporting  |
|--|--|--|
| Physical threats to a BES control center                 | RC, BA, TOP                                    | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at a BES control center. |
| BES Emergency requiring public appeal for load reduction | Initiating entity is responsible for reporting | Public appeal for load reduction event.  |
| BES Emergency requiring system-wide voltage reduction    | Initiating entity is responsible for reporting | System wide voltage reduction of 3% or more.   |
| BES Emergency requiring manual firm load shedding        | Initiating entity is responsible for reporting | Manual firm load shedding $\geq 100$ MW.   |
| BES Emergency resulting in automatic firm load shedding  | DP, TOP  | Automatic firm load shedding $\geq 100$ MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).   |
| Voltage deviation on a Facility                          | TOP  | Observed within its area a voltage deviation of $\pm 10\%$ of nominal voltage sustained for $\geq 15$ continuous minutes.  |

| Event Type   | Entity with Reporting Responsibility | Threshold for Reporting   |
|--|--------------------------------------|---|
| IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) | RC                                   | Operate outside the IROL for time greater than IROL $T_v$ (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).                       |
| Loss of firm load  | BA, TOP, DP                          | Loss of firm load for $\geq 15$ Minutes:<br>$\geq 300$ MW for entities with previous year's demand $\geq 3,000$<br>OR<br>$\geq 200$ MW for all other entities   |
| System separation (islanding)  | RC, BA, TOP                          | Each separation resulting in an island $\geq 100$ MW  |
| Generation loss  | BA, GOP                              | Total generation loss, within one minute, of :<br>$\geq 2,000$ MW for entities in the Eastern or Western Interconnection<br>OR<br>$\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection |
| Complete loss of off-site power to a nuclear generating plant (grid supply)                      | TO, TOP                              | Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement  |

| Event Type                                      | Entity with Reporting Responsibility | Threshold for Reporting   |
|---|--------------------------------------|---|
| Transmission loss                               | TOP                                  | Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).   |
| Unplanned BES control center evacuation         | RC, BA, TOP                          | Unplanned evacuation from BES control center facility for 30 continuous minutes or more.  |
| Complete loss of voice communication capability | RC, BA, TOP                          | Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.   |
| Complete loss of monitoring capability          | RC, BA, TOP                          | Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable. |

EOP-004 - Attachment 2: Event Reporting Form

| <b>EOP-004 Attachment 2: Event Reporting Form</b>   |  |
|---|--|
| <p><b>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: <a href="mailto:systemawareness@nerc.net">systemawareness@nerc.net</a> , Facsimile 404-446-9770 or voice: 404-446-9780.</b></p>  |  |
| Task  | Comments   |
| 1.  | Entity filing the report include:<br>Company name:<br>Name of contact person:<br>Email address of contact person:<br>Telephone Number:<br>Submitted by (name): |
| 2.  | Date and Time of recognized event.<br>Date: (mm/dd/yyyy)<br>Time: (hh:mm)<br>Time/Zone:  |
| 3.  | Did the event originate in your system?      Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/>                         |
| 4.  | <b>Event Identification and Description:</b>   |
| (Check applicable box)<br><input type="checkbox"/> Damage or destruction of a Facility<br><input type="checkbox"/> Physical Threat to a Facility<br><input type="checkbox"/> Physical Threat to a control center<br><input type="checkbox"/> BES Emergency:<br><input type="checkbox"/> public appeal for load reduction<br><input type="checkbox"/> system-wide voltage reduction<br><input type="checkbox"/> manual firm load shedding<br><input type="checkbox"/> automatic firm load shedding<br><input type="checkbox"/> Voltage deviation on a Facility<br><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)<br><input type="checkbox"/> Loss of firm load<br><input type="checkbox"/> System separation<br><input type="checkbox"/> Generation loss<br><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)<br><input type="checkbox"/> Transmission loss<br><input type="checkbox"/> unplanned control center evacuation<br><input type="checkbox"/> Complete loss of voice communication capability<br><input type="checkbox"/> Complete loss of monitoring capability | Written description (optional):  |



## Guideline and Technical Basis

### Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

### Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

### Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

### **Data Gathering**

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

### **Law Enforcement Reporting**

The reliability objective of EOP-004-2-3 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

### **Stakeholders in the Reporting Process**

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

### **Present expectations of the industry under CIP-001-1a:**

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

### **Coordination of Local and State Law Enforcement Agencies with the FBI**

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

### **Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**

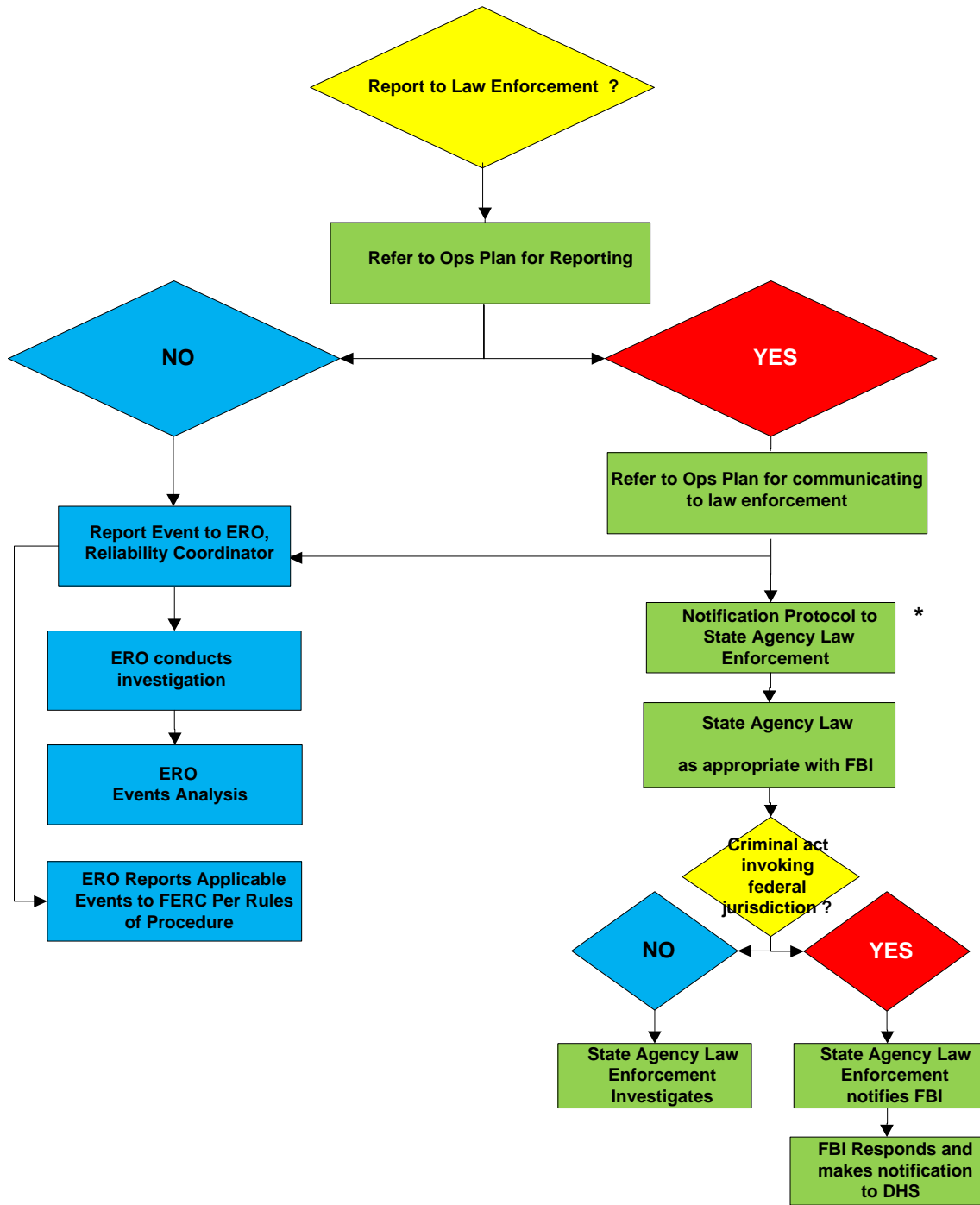
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

### **A Reporting Process Solution – EOP-004**

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



\* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

### Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

#### Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

#### Summary of Concepts and Assumptions:

##### *The Standard:*

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

##### **Discussion of Disturbance Reporting**

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

### **Discussion of Event Reporting**

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

### ***What about sabotage?***

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

### ***Potential Uses of Reportable Information***

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

### **Collection of Reportable Information or “One stop shopping”**

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

### **Rationale:**

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

### **Rationale for R1:**

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on



how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

### **Rationale for R2:**

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2-3 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

### **Rationale for R3:**

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

### **Rationale for EOP-004 Attachment 1:**

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

### Version History

| Version         | Date             | Action   | Change Tracking  |
|-----------------|------------------|--|--|
| 2               |                  | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01)  |
| 2               | November 7, 2012 | Adopted by the NERC Board of Trustees  |  |
| 2               | June 20, 2013    | FERC approved  |  |
| <del>2</del> -3 | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** System Operating Limits Methodology for the Planning Horizon
- 2. Number:** FAC-010-3
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
  - 4.1. Planning Authority**
- 5. Effective Date:** April 19, 2010

**B. Requirements**

- R1.** The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1.** Be applicable for developing SOLs used in the planning horizon.
  - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
  - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1.** In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2.** Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1.** Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3.** Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
    - R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
  - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
  - R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
  - R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
    - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
  - R3.2.** Selection of applicable Contingencies.
  - R3.3.** Level of detail of system models used to determine SOLs.
  - R3.4.** Allowed uses of Remedial Action Schemes.
  - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
  - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
  - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
  - R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### **C. Measures**

- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### **1.3. Data Retention**

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### **1.4. Additional Compliance Information**

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

##### **1.4.1** SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

##### **1.4.2** Superseded portions of its SOL Methodology that had been made within the past 12 months.

##### **1.4.3** Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

### **2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**

#### **2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:

##### **2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

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- 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology.  
(Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
  - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
  - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
  - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

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**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6  |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |

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| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |



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| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

**E. Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

## Standard FAC-010-3 — System Operating Limits Methodology for the Planning Horizon

- 1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
- 1.3.1** Cascading does not occur.
- 1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

### Version History

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |

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|-----|-------------------|--|--|
| 2.1 | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |  |
| 2.1 | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.  |  |
| 3   | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** System Operating Limits Methodology for the Planning Horizon
2. **Number:** FAC-010-~~32-1~~
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Planning Authority
5. **Effective Date:** April 19, 2010

## B. Requirements

- R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
  - R1.1. Be applicable for developing SOLs used in the planning horizon.
  - R1.2. State that SOLs shall not exceed associated Facility Ratings.
  - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2. Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
    - R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

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<sup>1</sup> The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
  - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
  - R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
  - R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
    - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
  - R3.2.** Selection of applicable Contingencies.
  - R3.3.** Level of detail of system models used to determine SOLs.
  - R3.4.** Allowed uses of Remedial Action Schemes.
  - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
  - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
  - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
  - R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

### C. Measures

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- M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

##### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

##### 1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

##### 1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

###### 1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)

###### 1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

###### 1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

#### 2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

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- 2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
  - 2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
  - 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
  - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
  - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
  - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4



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**3. Violation Severity Levels:**

| Requirement | Lower  | Moderate   | High   | Severe  |
|-------------|--|--|--|---|
| R1          | Not applicable.  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2  | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.   | The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1.<br>OR<br>The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.                             |
| R2          | The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.   | The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6   | The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.  | The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6  |
| R3          | The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.   | The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.  |
| R4          | One or both of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities.<br>For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. | One of the following:<br>The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities.<br>The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in |

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| Requirement | Lower  | Moderate   | High  | Severe   |
|-------------|--|--|---|--|
|             |  | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> | <p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p> |
| R5          | The Planning Authority received documented technical | The Planning Authority received documented technical   | The Planning Authority received documented technical  | The Planning Authority received documented technical   |

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| Requirement  | Lower  | Moderate   | High   | Severe  |
|--|--|--|--|---|
| <p>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

## E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version | Date             | Action  | Change Tracking |
|---------|------------------|---|-----------------|
| 1       | November 1, 2006 | Adopted by Board of Trustees  | New             |
| 1       | November 1, 2006 | Fixed typo. Removed the word “each” from the 1 <sup>st</sup> sentence of section D.1.3, Data Retention.   | 01/11/07        |
| 2       | June 24, 2008    | Adopted by Board of Trustees; FERC Order 705  | Revised         |
| 2       |                  | Changed the effective date to July 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels                   | Revised         |
| 2       | January 22, 2010 | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update          |
| 2.1     | November 5, 2009 | Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. | Errata          |
| 2.1     | April 19, 2010   | FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.                    | Errata          |
| 2.1     | February 7, 2013 | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.    |                 |

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|                 |                   |  |  |
|-----------------|-------------------|--|--|
| 2.1             | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) |  |
| 2.1             | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.  |  |
| <del>32.1</del> | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** System Operating Limits Methodology for the Operations Horizon
- 2. Number:** FAC-011-3
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
  - 4.1.** Reliability Coordinator
- 5. Effective Date:** April 29, 2009

**B. Requirements**

- R1.** The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1.** Be applicable for developing SOLs used in the operations horizon.
  - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
  - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Reliability Coordinator’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1.** In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2.** Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1.** Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3.** In determining the system’s response to a single Contingency, the following shall be acceptable:

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
    - R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
    - R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
  - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R3.** The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
  - R3.2.** Selection of applicable Contingencies
  - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
    - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
  - R3.4.** Level of detail of system models used to determine SOLs.
  - R3.5.** Allowed uses of Remedial Action Schemes.
  - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
  - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
  - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.
  - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)



## C. Measures

- M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### 1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### 1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

##### 1.4.1 SOL Methodology.

- 1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)
  - 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
  - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
2. **Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology  
(Retirement approved by FERC effective January 21, 2014.)
  - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
  - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
  - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |

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| Requirement   | Lower   | Moderate  | High  | Severe   |
|---|---|---|---|--|
|   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>   |
| <p>R5<br/>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

## **Regional Differences**

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1.** As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2** Cascading does not occur.
    - 1.2.3** Uncontrolled separation of the system does not occur.
    - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------------|---|--|
| 1              | November 1, 2006  | Adopted by Board of Trustees  | New  |
| 2              |                   | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised  |
| 2              | June 24, 2008     | Adopted by Board of Trustees: FERC Order 705  | Revised  |
| 2              | January 22, 2010  | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update   |
| 2              | February 7, 2013  | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |  |
| 2              | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |  |
| 2              | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.   |  |
| 3              | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-~~32~~
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
  - 4.1. Reliability Coordinator
5. **Effective Date:** April 29, 2009

## B. Requirements

- R1.** The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
  - R1.1.** Be applicable for developing SOLs used in the operations horizon.
  - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
  - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
  - R2.1.** In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
  - R2.2.** Following the single Contingencies<sup>1</sup> identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
    - R2.2.1.** Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
    - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
    - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
  - R2.3.** In determining the system's response to a single Contingency, the following shall be acceptable:

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<sup>1</sup> The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
  - R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
  - R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R3.** The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
  - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
  - R3.2.** Selection of applicable Contingencies
  - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
    - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
  - R3.4.** Level of detail of system models used to determine SOLs.
  - R3.5.** Allowed uses of Remedial Action Schemes.
  - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
  - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL  $T_v$ .
- R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
  - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
  - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.
  - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)



## C. Measures

- M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

#### 1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

#### 1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

**1.4.1** SOL Methodology.

- 1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.  
(Retirement approved by FERC effective January 21, 2014.)
  - 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
  - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
2. **Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
    - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
    - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology  
(Retirement approved by FERC effective January 21, 2014.)
  - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
  - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
    - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
    - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
    - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
  - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

| Requirement | Lower  | Moderate  | High  | Severe  |
|-------------|--|---|---|---|
| R1          | Not applicable.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2                     | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.  | The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1.<br>OR<br>The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area. |
| R2          | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1) | Not applicable.   | The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4) | The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)  |
| R3          | The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.  | The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.   | The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.   |
| R3.6        | N/A  | N/A   | N/A   | N/A   |
| R4          | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.  | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3. | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.   | The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3   |

| Requirement   | Lower   | Moderate  | High  | Severe   |
|---|---|---|---|--|
|   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p> | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>   | <p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>   |
| <p>R5<br/>(Retirement approved by FERC effective January 21, 2014.)</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>  | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p> | <p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p> |

## Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
  - 1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
    - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
    - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
    - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
    - 1.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
    - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
    - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
    - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
  - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
    - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
    - 1.2.2 Cascading does not occur.
    - 1.2.3 Uncontrolled separation of the system does not occur.
    - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
    - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
    - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
  - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

**Version History**

| Version       | Date              | Action  | Change Tracking  |
|---------------|-------------------|---|--|
| 1             | November 1, 2006  | Adopted by Board of Trustees  | New  |
| 2             |                   | Changed the effective date to October 1, 2008<br>Changed “Cascading Outage” to “Cascading”<br>Replaced Levels of Non-compliance with Violation Severity Levels<br>Corrected footnote 1 to reference FAC-011 rather than FAC-010 | Revised  |
| 2             | June 24, 2008     | Adopted by Board of Trustees: FERC Order 705  | Revised  |
| 2             | January 22, 2010  | Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order  | Update   |
| 2             | February 7, 2013  | R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.  |  |
| 2             | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)  |  |
| 2             | February 24, 2014 | Updated VSLs based on June 24, 2013 approval.   |  |
| <del>32</del> | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** **Reliability Coordination — Current Day Operations**
2. **Number:** IRO-005-3.1(i)a
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Transmission Service Providers.
  - 4.5. Generator Operators.
  - 4.6. Load-Serving Entities.
  - 4.7. Purchasing-Selling Entities.
5. **Effective Date:**

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

**B. Requirements**

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
  - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.
  - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.4. System real and reactive reserves (actual versus required).
  - R1.5. Capacity and energy adequacy conditions.
  - R1.6. Current ACE for all its Balancing Authorities.

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.



- R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

**C. Measures**

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance

outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

## **D. Compliance**

### **1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

**1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

**1.3. Data Retention**

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

**1.4. Additional Compliance Information**

None.

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

**2. Violation Severity Levels:**

| Requirement | Lower   | Moderate  | High  | Severe  |
|-------------|---|---|---|---|
| R1          | The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10.   | The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10. | The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10. | The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10. |
| R1.1        | The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.  | N/A   | N/A   | N/A   |
| R1.2        | The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A   | N/A   | N/A   |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower  | Moderate | High | Severe |
|-------------|--|----------|------|--------|
| R1.3        | The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A      | N/A  | N/A    |
| R1.4        | The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).  | N/A      | N/A  | N/A    |
| R1.5        | The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.   | N/A      | N/A  | N/A    |
| R1.6        | The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.   | N/A      | N/A  | N/A    |
| R1.7        | The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.   | N/A      | N/A  | N/A    |
| R1.8        | The Reliability Coordinator failed to monitor planned generation dispatches.   | N/A      | N/A  | N/A    |
| R1.9        | The Reliability Coordinator failed to monitor planned transmission or generation outages.  | N/A      | N/A  | N/A    |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower   | Moderate   | High  | Severe  |
|-------------|---|--|---|---|
| R1.10       | The Reliability Coordinator failed to monitor contingency events. | N/A  | N/A   | N/A   |
| R2          | N/A   | The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. | The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.  | The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. |
| R3          | N/A   | N/A  | The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans. | The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.  |
| R4          | N/A   | N/A  | N/A   | The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.   |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

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| Requirement | Lower | Moderate | High  | Severe  |
|-------------|-------|----------|---|---|
| R5          | N/A   | N/A      | The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance. | The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition. |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High  | Severe   |
|-------------|-------|--|---|--|
| R6          | N/A   | <p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real-time reliability analysis time frame or the next-day reliability analysis</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> |
| R7          | N/A   | N/A  | N/A   | <p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>   |



**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
| R8          | N/A   | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS. | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority. | The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.  |
| R9          | N/A   | N/A  | N/A  | The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Remedial Action Scheme that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected. |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
| R10         | N/A   | N/A  | N/A  | The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.   |
| R11         | N/A   | N/A  | N/A  | The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.  |
| R12         | N/A   | The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated. | N/A  | The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities. |

**E. Regional Differences**

None identified.

**Version History**

| Version | Date               | Action  | Change Tracking |
|---------|--------------------|---|-----------------|
| 0       | April 1, 2005      | Effective Date  | New             |
| 0       | August 8, 2005     | Removed “Proposed” from Effective Date  | Errata          |
| 1       |                    | Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17<br>Retired M2 and M3; modified M9 and M12; retired M13<br>Made conforming changes to data retention<br>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)<br>Retired VSLs associated with R2, R3, R5, R16 and R17;<br>Modified VSLs associated with R9 and R13, and R14 | Revised         |
| 2       | November 1, 2006   | Approved by the Board of Trustees   |                 |
| 2       | January 1, 2007    | Effective Date  |                 |
| 2a      | November 5, 2009   | Approved by the Board of Trustees   |                 |
| 3       | October 17, 2008   | Approved by the Board of Trustees   |                 |
| 3       | March 17, 2011     | Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)   |                 |
| 3a      | April 21, 2011     | Added FERC approved Interpretation  |                 |
| 3.1a    | March 8, 2012      | Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)  | Errata          |
| 3.1a    | September 13, 2012 | FERC approved   | Errata          |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

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|         |                   |   |  |
|---------|-------------------|---|--|
| 3.1a    | February 28, 2014 | Updated VSLs based on June 24, 2013 approval. |  |
| 3.1(i)a | TBD               | Adopted by the NERC Board of Trustees         | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Appendix 1

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3</b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12<sup>1</sup></b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0 Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation  |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>   |

<sup>1</sup> In the current version of the Standard (IRO-005-3a), this requirement is R9.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-3.1(i)a
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
  - 4.1. Reliability Coordinators.
  - 4.2. Balancing Authorities.
  - 4.3. Transmission Operators.
  - 4.4. Transmission Service Providers.
  - 4.5. Generator Operators.
  - 4.6. Load-Serving Entities.
  - 4.7. Purchasing-Selling Entities.
5. **Effective Date:**

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

## B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
  - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.
  - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
  - R1.4. System real and reactive reserves (actual versus required).
  - R1.5. Capacity and energy adequacy conditions.
  - R1.6. Current ACE for all its Balancing Authorities.

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.



- R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

**C. Measures**

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance

outages with Transmission Operators, Balancing Authorities and Generator Operators.  
(Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

## **D. Compliance**

### **1. Compliance Monitoring Process**

### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

**2. Violation Severity Levels:**

| Requirement | Lower   | Moderate  | High  | Severe  |
|-------------|---|---|---|---|
| R1          | The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10.   | The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10. | The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10. | The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-3.1(i)a R1.1 through R1.10. |
| R1.1        | The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.  | N/A   | N/A   | N/A   |
| R1.2        | The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A   | N/A   | N/A   |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower  | Moderate | High | Severe |
|-------------|--|----------|------|--------|
| R1.3        | The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope. | N/A      | N/A  | N/A    |
| R1.4        | The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).  | N/A      | N/A  | N/A    |
| R1.5        | The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.   | N/A      | N/A  | N/A    |
| R1.6        | The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.   | N/A      | N/A  | N/A    |
| R1.7        | The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.   | N/A      | N/A  | N/A    |
| R1.8        | The Reliability Coordinator failed to monitor planned generation dispatches.   | N/A      | N/A  | N/A    |
| R1.9        | The Reliability Coordinator failed to monitor planned transmission or generation outages.  | N/A      | N/A  | N/A    |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower   | Moderate   | High  | Severe  |
|-------------|---|--|---|---|
| R1.10       | The Reliability Coordinator failed to monitor contingency events. | N/A  | N/A   | N/A   |
| R2          | N/A   | The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. | The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.  | The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. |
| R3          | N/A   | N/A  | The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans. | The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.  |
| R4          | N/A   | N/A  | N/A   | The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.   |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

| Requirement | Lower | Moderate | High  | Severe  |
|-------------|-------|----------|---|---|
| R5          | N/A   | N/A      | The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance. | The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition. |

Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High  | Severe   |
|-------------|-------|--|---|--|
| R6          | N/A   | <p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real-time reliability analysis time frame or the next-day reliability analysis</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> | <p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p> |
| R7          | N/A   | N/A  | N/A   | <p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>   |



Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
| R8          | N/A   | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS. | The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority. | The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.  |
| R9          | N/A   | N/A  | N/A  | The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Remedial Action Scheme that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected. |

Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
| R10         | N/A   | N/A  | N/A  | The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.   |
| R11         | N/A   | N/A  | N/A  | The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.  |
| R12         | N/A   | The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated. | N/A  | The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities. |

**E. Regional Differences**

None identified.

**Version History**

| Version | Date               | Action  | Change Tracking |
|---------|--------------------|---|-----------------|
| 0       | April 1, 2005      | Effective Date  | New             |
| 0       | August 8, 2005     | Removed “Proposed” from Effective Date  | Errata          |
| 1       |                    | Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17<br>Retired M2 and M3; modified M9 and M12; retired M13<br>Made conforming changes to data retention<br>Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)<br>Retired VSLs associated with R2, R3, R5, R16 and R17;<br>Modified VSLs associated with R9 and R13, and R14 | Revised         |
| 2       | November 1, 2006   | Approved by the Board of Trustees   |                 |
| 2       | January 1, 2007    | Effective Date  |                 |
| 2a      | November 5, 2009   | Approved by the Board of Trustees   |                 |
| 3       | October 17, 2008   | Approved by the Board of Trustees   |                 |
| 3       | March 17, 2011     | Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)   |                 |
| 3a      | April 21, 2011     | Added FERC approved Interpretation  |                 |
| 3.1a    | March 8, 2012      | Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)  | Errata          |
| 3.1a    | September 13, 2012 | FERC approved   | Errata          |

**Standard IRO-005-3.1(i)a — Reliability Coordination — Current Day Operations**

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|         |                   |   |  |
|---------|-------------------|---|--|
| 3.1a    | February 28, 2014 | Updated VSLs based on June 24, 2013 approval. |  |
| 3.1(i)a | TBD               | Adopted by the NERC Board of Trustees         | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## Appendix 1

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3</b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p style="text-align: center;"><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12<sup>1</sup></b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0 Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation  |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>   |

<sup>1</sup> In the current version of the Standard (IRO-005-3a), this requirement is R9.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## A. Introduction

1. **Title:** **Rated System Path Methodology**
2. **Number:** **MOD-029-2a**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

## B. Requirements

- R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1. Includes at least:
      - R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)
    - R1.1.2. Models all system Elements as in-service for the assumed initial conditions.
    - R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
    - R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).





Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**NL<sub>F</sub>** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the

effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

### C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

**1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |

**Standard MOD-029-2a — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |



**Standard MOD-029-2a — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |

**Version History**

| <b>Version</b> | <b>Date</b>                  | <b>Action</b>                                    | <b>Change Tracking</b>   |
|----------------|------------------------------|--|--|
| 1              | 8/26/2008                    | Adopted by NERC Board of Trustees                |  |
| 1a             | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)  |
| 1a             | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |  |
| 2a             | TBD                          | Adopted by the NERC Board of Trustees            | Replaced references to<br>Special Protection<br>System and SPS with<br>Remedial Action Scheme<br>and RAS |

Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> <li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li> <li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li> <li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li> </ul> <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> <li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li> <li><b>R8.2.</b> Daily values, once per day.</li> <li><b>R8.3.</b> Monthly values, once per week.</li> </ul> |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>   |

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01 Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments ( $ETC_F$ ) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NL_F$  is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$  is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_F$  is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

$PTP_F$  is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$ROR_F$  is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

$OS_F$  is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ( $ETC_{NF}$ ) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$  is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_{NF}$  is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_{NF}$  is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

$OS_{NF}$  is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could  $OS_F$  in MOD-029-1 Requirement R5 and  $OS_{NF}$  in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## A. Introduction

1. **Title:** Rated System Path Methodology
2. **Number:** MOD-029-~~21~~a
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
  - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

## B. Requirements

- R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
  - R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
    - R1.1.1. Includes at least:
      - R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
      - R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
      - R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)
    - R1.1.2. Models all system Elements as in-service for the assumed initial conditions.
    - R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
    - R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

- R1.1.5.** Uses Load forecast by Balancing Authority.
  - R1.1.6.** Uses Transmission Facility additions and retirements.
  - R1.1.7.** Uses Generation Facility additions and retirements.
  - R1.1.8.** Uses Remedial Action Scheme (RAS) models where currently existing or projected for implementation within the studied time horizon.
  - R1.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
  - R1.1.10.** Includes any other modeling requirements or criteria specified in the ATCID.
- R1.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R2.** The Transmission Operator shall use the following process to determine TTC:  
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
  - R2.1.** Except where otherwise specified within MOD-029-21a, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:
    - R2.1.1.** When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
    - R2.1.2.** When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
    - R2.1.3.** Uncontrolled separation shall not occur.
  - R2.2.** Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Remedial Action Scheme (RAS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a RAS.
  - R2.3.** For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.
  - R2.4.** For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.
  - R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path.

Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC<sub>F</sub>) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

**Where:**

**NL<sub>F</sub>** is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**NITS<sub>F</sub>** is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>F</sub>** is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the



effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>F</sub>** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

**ROR<sub>F</sub>** is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

**OS<sub>F</sub>** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC<sub>NF</sub>) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

**Where:**

**NITS<sub>NF</sub>** is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

**GF<sub>NF</sub>** is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

**PTP<sub>NF</sub>** is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

**OS<sub>NF</sub>** is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

**Where**

**ATC<sub>F</sub>** is the firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**CBM** is the Capacity Benefit Margin for the ATC Path during that period.

**TRM** is the Transmission Reliability Margin for the ATC Path during that period.

**Postbacks<sub>F</sub>** are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>F</sub>** are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

**Where:**

**ATC<sub>NF</sub>** is the non-firm Available Transfer Capability for the ATC Path for that period.

**TTC** is the Total Transfer Capability of the ATC Path for that period.

**ETC<sub>F</sub>** is the sum of existing firm commitments for the ATC Path during that period.

**ETC<sub>NF</sub>** is the sum of existing non-firm commitments for the ATC Path during that period.

**CBM<sub>S</sub>** is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

**TRM<sub>U</sub>** is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

### C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-~~21~~ and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

#### **1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

#### **1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL  |
|-----|--|--|--|---|
| R1. | <p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p> | <p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;"><b>OR</b></p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>    |
| R2  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include one required item in the study report required in R2.8.</li> </ul>   | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include two required items in the study report required in R2.8.</li> </ul>  | <p>One or both of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator does not include three required items in the study report required in R2.8.</li> </ul>  | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6.</li> <li>The Transmission Operator did not apply R2.7.</li> <li>The Transmission Operator does not include four or more required items in the study report required in R2.8</li> </ul> |

**Standard MOD-029-21a — Rated System Path Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R3. | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  | The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).  |
| R4. | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.   | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.  | The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.  |
| R5. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |

Standard MOD-029-21a — Rated System Path Methodology

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
| R6. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R7. | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).   |



**Version History**

| Version         | Date                         | Action   | Change Tracking  |
|-----------------|------------------------------|--|--|
| 1               | 8/26/2008                    | Adopted by NERC Board of Trustees                |  |
| 1a              | Board approved<br>11/05/2009 | Interpretation of R5 and R6                      | Interpretation (Project<br>2009-15)  |
| 1a              | February 28,<br>2014         | Updated VSLs based on June 24, 2013<br>approval. |  |
| <del>21</del> a | TBD                          | Adopted by the NERC Board of Trustees            | Replaced references to<br>Special Protection<br>System and SPS with<br>Remedial Action Scheme<br>and RAS |

## Appendix 1

| Requirement Number and Text of Requirement  |
|---|
| <p><b>MOD-001-01 Requirement R2:</b></p> <p><b>R2.</b> Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> <li><b>R2.1.</b> Hourly values for at least the next 48 hours.</li> <li><b>R2.2.</b> Daily values for at least the next 31 calendar days.</li> <li><b>R2.3.</b> Monthly values for at least the next 12 months (months 2-13).</li> </ul> <p><b>MOD-001-01 Requirement R8:</b></p> <p><b>R8.</b> Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> <li><b>R8.1.</b> Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.</li> <li><b>R8.2.</b> Daily values, once per day.</li> <li><b>R8.3.</b> Monthly values, once per week.</li> </ul> |
| Question #1   |
| <p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>   |
| Response to Question #1   |
| <p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>   |

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

**Requirement Number and Text of Requirement**

**MOD-029-01 Requirements R5 and R6:**

**R5.** When calculating ETC for firm Existing Transmission Commitments ( $ETC_F$ ) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$NL_F$  is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$  is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_F$  is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

$PTP_F$  is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$ROR_F$  is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

$OS_F$  is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

**R6.** When calculating ETC for non-firm Existing Transmission Commitments ( $ETC_{NF}$ ) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$  is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$GF_{NF}$  is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$PTP_{NF}$  is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

$OS_{NF}$  is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

**Question #2**

Could  $OS_F$  in MOD-029-1 Requirement R5 and  $OS_{NF}$  in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

**Response to Question #2**

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

## A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** **MOD-030-3**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

## B. Requirements

- R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3. The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
      - R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the

applicable time periods, including use of Remedial Action Schemes.

**R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

**R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

**R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

**R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
  - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

**R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

- R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ( $ETC_{Fi}$ ) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load



- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
  - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
  - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC<sub>NFI</sub>) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.

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<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

**C. Measures**

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

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<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the

value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

#### **1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |



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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |

**Standard MOD-030-3 — Flowgate Methodology**

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>• The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>• The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>• The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>• The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>• The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>   | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>  |

**Standard MOD-030-3 — Flowgate Methodology**

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>• The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>• The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |

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| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

**Standard MOD-030-3 — Flowgate Methodology**

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |

**Standard MOD-030-3 — Flowgate Methodology**

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| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| <b>Version</b> | <b>Date</b> | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------|---|--|
| 2              |             | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised  |
| 3              | TBD         | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** **Flowgate Methodology**
2. **Number:** **MOD-030-~~302~~**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
  - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
  - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

## B. Requirements

- R1.** The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R1.1.** The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
  - R1.2.** The following information on how source and sink for transmission service is accounted for in AFC calculations including:
    - R1.2.1.** Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
    - R1.2.2.** Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
    - R1.2.3.** The source/sink or POR/POD identification and mapping to the model.
    - R1.2.4.** If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2.** The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
  - R2.1.** Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
    - R2.1.1.** Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
      - R2.1.1.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the



applicable time periods, including use of Remedial Action Schemes.

**R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

**R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

**R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.

**R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

**R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

**R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

**R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

**R2.1.4.2.** The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
  - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.
- R3.** The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.
- R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
  - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

**R5.** When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R5.1.** Use the models provided by the Transmission Operator.

**R5.2.** Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

**R5.3.** For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

**R6.** When calculating the impact of ETC for firm commitments ( $ETC_{Fi}$ ) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R6.1.** The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

**R6.1.1.** Load forecast for the time period being calculated, including Native Load and Network Service load

- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
  - R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage<sup>1</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
    - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
    - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
  - R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
  - R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage<sup>2</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
  - R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>3</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
  - R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC<sub>NFI</sub>) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

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<sup>1</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>2</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>3</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage<sup>4</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage<sup>5</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage<sup>6</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + counterflows_{Fi}$$

**Where:**

**AFC<sub>F</sub>** is the firm Available Flowgate Capability for the Flowgate for that period.

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<sup>4</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>5</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

<sup>6</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**CBM<sub>i</sub>** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**TRM<sub>i</sub>** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**Postbacks<sub>Fi</sub>** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>Fi</sub>** are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

**Where:**

**AFC<sub>NF</sub>** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**ETC<sub>Fi</sub>** is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

**ETC<sub>NFi</sub>** is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

**CBM<sub>Si</sub>** is the impact of any schedules during that period using Capacity Benefit Margin.

**TRM<sub>Ui</sub>** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

**Postbacks<sub>NF</sub>** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**counterflows<sub>NF</sub>** are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

**R10.1.** For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

**R10.2.** For daily AFC, once per day.

**R10.3.** For monthly AFC, once per week.

- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage<sup>7</sup> used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC<sub>n</sub>** is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

**AFC<sub>n</sub>** is the Available Flowgate Capability of a Flowgate *n*.

**DF<sub>np</sub>** is the distribution factor for Flowgate *n* relative to path *p*.

**C. Measures**

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

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<sup>7</sup> A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the



value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

**M17.** The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

**M18.** The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Data Retention**

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

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

#### **1.4. Compliance Monitoring and Enforcement Processes:**

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

**1.5. Additional Compliance Information**

None.

2. Violation Severity Levels

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|-----|---|--|--|--|
| R1. | The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.   | The Transmission Service Provider does not include in its ATCID the information described in R1.1.<br><br><b>OR</b><br>The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  | The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).  |
| R2. | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3.</li> </ul> | One or more of the following: <ul style="list-style-type: none"> <li>The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1.</li> <li>The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2.</li> <li>The Transmission Operator did not establish its list of internal Flowgates as described in R2.2.</li> <li>The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a</li> </ul> |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | <p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination.</li> </ul> | <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update.</li> <li>The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination.</li> </ul> | <p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination.</li> </ul> | <p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3.</li> <li>The Transmission Operator did not determine the TFC for a flowgate as described in R2.4.</li> <li>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5)</li> <li>The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1)</li> <li>The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.</li> </ul> |

| R # | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL  |
|-----|---|--|--|---|
| R3. | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>The Transmission Operator did not update the model per R3.2 for more than 4 calendar days</li> <li>The Transmission Operator did not update the model for per R3.3 for more than ten weeks</li> <li>The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</li> <li>The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area.</li> <li>The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.</li> </ul> |
| R4. | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>   | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>  | <p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>  |

| R # | Lower VSL  | Moderate VSL   | High VSL   | Severe VSL   |
|-----|--|--|--|--|
|     | 5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..   | 10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..  | 15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..  | more than 3 reservations, whichever is greater..   |
| R5. | The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.   | One or more of the following: <ul style="list-style-type: none"> <li>• The Transmission Service Provider did not use the model provided by the Transmission Operator.</li> <li>• The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.</li> <li>• The Transmission Service provider did not use AFC provided by a third party.</li> </ul> |
| R6. | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value | For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.  |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL  |
|-----|---|---|---|---|
|     | calculated in the measure or 25MW, whichever is greater..   | calculated in the measure or 35MW, whichever is greater.  | calculated in the measure or 45MW, whichever is greater.  |   |
| R7. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater. | For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater. |
| R8. | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).  |
| R9. | The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates  | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all   | The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all   |

| R # | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----|---|---|---|--|
|     | Flowgates or 1 Flowgate (whichever is greater).   | or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).   | Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).  | Flowgates or more than 3 Flowgates (whichever is greater).   |
| R10 | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days.</li> </ul> | <p>One or more of the following:</p> <ul style="list-style-type: none"> <li>▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement.</li> <li>▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days.</li> <li>▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.</li> </ul> |



| R #  | Lower VSL | Moderate VSL | High VSL | Severe VSL  |
|------|-----------|--------------|----------|---|
| R11. | N/A       | N/A          | N/A      | The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11. |

**A. Regional Differences**

None identified.

**B. Associated Documents**

**Version History**

| Version       | Date | Action  | Change Tracking  |
|---------------|------|---|--|
| 2             |      | Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11<br>Made conforming changes to M18 and VSLs for R2 and R11 | Revised  |
| <del>32</del> | TBD  | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** Nuclear Plant Interface Coordination
- 2. Number:** NUC-001-2.1(i)
- 3. Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
- 4. Applicability:**
  - 4.1.** Nuclear Plant Generator Operator.
  - 4.2.** Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
    - 4.2.1** Transmission Operators.
    - 4.2.2** Transmission Owners.
    - 4.2.3** Transmission Planners.
    - 4.2.4** Transmission Service Providers.
    - 4.2.5** Balancing Authorities.
    - 4.2.6** Reliability Coordinators.
    - 4.2.7** Planning Coordinators.
    - 4.2.8** Distribution Providers.
    - 4.2.9** Load-serving Entities.
    - 4.2.10** Generator Owners.
    - 4.2.11** Generator Operators.
- 5. Effective Date:** April 1, 2010

**B. Requirements**

- R1.** The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements<sup>1</sup> that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]
- R3.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

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1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
  - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
  - R4.2.** Operate the electric system to meet the NPIRs.
  - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
  - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
  - R9.2.** Technical requirements and analysis:
    - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.
    - R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
    - R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
  - R9.3.** Operations and maintenance coordination:

- R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
- R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
- R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
- R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
- R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
- R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
- R9.3.7.** Coordination of the NPIRs with transmission system Remedial Action Schemes and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
  - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
  - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
  - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
  - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
  - R9.4.5.** Provisions for personnel training, as related to NPIRs.

**C. Measures**

- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
  - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
  - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
  - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Enforcement Authority**

Regional Entity.
  - 1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.
  - 1.3. Compliance Monitoring and Enforcement Processes:**
    - Compliance Audits
    - Self-Certifications
    - Spot Checking
    - Compliance Violation Investigations
    - Self-Reporting

Complaints

**1.4. Data Retention**

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

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

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

**1.5. Additional Compliance Information**

None.

**2. Violation Severity Levels**

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

**E. Regional Differences**

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

**Nuclear Plant Licensing Requirements (NPLR)** are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this

## Standard NUC-001-2.1(i) — Nuclear Plant Interface Coordination

standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

### F. Associated Documents

#### Version History

| Version | Date              | Action   | Change Tracking  |
|---------|-------------------|--|--|
| 1       | May 2, 2007       | Approved by Board of Trustees  | New  |
| 2       | To be determined  | Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.                             | Revision   |
| 2       | August 5, 2009    | Adopted by Board of Trustees   | Revised  |
| 2       | January 22, 2010  | Approved by FERC on January 21, 2010<br>Added Effective Date   | Update   |
| 2       | February 7, 2013  | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. |  |
| 2.1     | April 11, 2012    | Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)                   | Errata associated with Project 2007-17   |
| 2.1     | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.   |  |
| 2.1     | November 21, 2013 | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)   |  |
| 2.1(i)  | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



**A. Introduction**

1. **Title:** Nuclear Plant Interface Coordination
2. **Number:** NUC-001-2.1(i)
3. **Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
4. **Applicability:**
  - 4.1. Nuclear Plant Generator Operator.
  - 4.2. Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
    - 4.2.1 Transmission Operators.
    - 4.2.2 Transmission Owners.
    - 4.2.3 Transmission Planners.
    - 4.2.4 Transmission Service Providers.
    - 4.2.5 Balancing Authorities.
    - 4.2.6 Reliability Coordinators.
    - 4.2.7 Planning Coordinators.
    - 4.2.8 Distribution Providers.
    - 4.2.9 Load-serving Entities.
    - 4.2.10 Generator Owners.
    - 4.2.11 Generator Operators.
5. **Effective Date:** April 1, 2010

**B. Requirements**

- R1. The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements<sup>1</sup> that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]
- R3. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

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1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
  - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
  - R4.2.** Operate the electric system to meet the NPIRs.
  - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
  - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
    - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
  - R9.2.** Technical requirements and analysis:
    - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.
    - R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
    - R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
  - R9.3.** Operations and maintenance coordination:

- R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
- R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
- R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
- R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
- R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
- R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
- R9.3.7.** Coordination of the NPIRs with transmission system Remedial Action Schemes and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
  - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
  - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
  - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
  - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
  - R9.4.5.** Provisions for personnel training, as related to NPIRs.

**C. Measures**

- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
  - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
  - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
  - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity.

#### **1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.

#### **1.3. Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.4. Data Retention**

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

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

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

**1.5. Additional Compliance Information**

None.

**2. Violation Severity Levels**

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

**E. Regional Differences**

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

**Nuclear Plant Licensing Requirements (NPLR)** are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this

## Standard NUC-001-2.1(i) — Nuclear Plant Interface Coordination

standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

### F. Associated Documents

#### Version History

| Version | Date              | Action   | Change Tracking  |
|---------|-------------------|--|--|
| 1       | May 2, 2007       | Approved by Board of Trustees  | New  |
| 2       | To be determined  | Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.                             | Revision   |
| 2       | August 5, 2009    | Adopted by Board of Trustees   | Revised  |
| 2       | January 22, 2010  | Approved by FERC on January 21, 2010<br>Added Effective Date   | Update   |
| 2       | February 7, 2013  | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. |  |
| 2.1     | April 11, 2012    | Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)                   | Errata associated with Project 2007-17   |
| 2.1     | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.   |  |
| 2.1     | November 21, 2013 | R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)   |  |
| 2.1(i)  | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(i)
3. **Purpose:**  
To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** January 1, 2007

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.
- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

### **C. Measures**

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 6 Part 2)

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

##### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will



have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

## **2. Levels of Non-Compliance for Generator Operators:**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

## **3. Levels of Non-Compliance for Transmission Operators:**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

**3.3. Level 3:** Not applicable.

**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

**3.4.2** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**4. Levels of Non-Compliance for Balancing Authorities:**

**4.1. Level 1:** Not applicable.

**4.2. Level 2:** Not applicable.

**4.3. Level 3:** Not applicable.

**4.4. Level 4:** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

**E. Regional Differences**

None identified.

**Version History**

| <b>Version</b> | <b>Date</b>       | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|-------------------|---|--|
| 0              | April 1, 2005     | Effective Date  | New  |
| 0              | August 8, 2005    | Removed “Proposed” from Effective Date  | Errata   |
| 0              | August 25, 2005   | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata   |
| 1              | November 1, 2006  | Adopted by Board of Trustees  | Revised  |
| 1.1            | April 11, 2012    | Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”) | Errata associated with Project 2007-17   |
| 1.1            | September 9, 2013 | Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.  |  |
| 1.1(i)         | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(i)
3. **Purpose:**  
To ensure system protection is coordinated among operating entities.
4. **Applicability**
  - 4.1. Balancing Authorities
  - 4.2. Transmission Operators
  - 4.3. Generator Operators
5. **Effective Date:** January 1, 2007

## B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
  - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
  - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
  - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
  - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.
- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

### **C. Measures**

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 6 Part 2)

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Regional Reliability Organizations shall be responsible for compliance monitoring.

##### **1.2. Compliance Monitoring and Reset Time Frame**

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will

have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

### **1.3. Data Retention**

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

### **1.4. Additional Compliance Information**

None.

## **2. Levels of Non-Compliance for Generator Operators:**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

## **3. Levels of Non-Compliance for Transmission Operators:**

**3.1. Level 1:** Not applicable.

**3.2. Level 2:** Not applicable.

**3.3. Level 3:** Not applicable.

**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

| Version | Date              | Action  | Change Tracking  |
|---------|-------------------|---|--|
| 0       | April 1, 2005     | Effective Date  | New  |
| 0       | August 8, 2005    | Removed “Proposed” from Effective Date  | Errata   |
| 0       | August 25, 2005   | Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0   | Errata   |
| 1       | November 1, 2006  | Adopted by Board of Trustees  | Revised  |
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| 1.1(i)  | TBD               | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-2
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

**4. Applicability**

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** On the first day of the second quarter following applicable regulatory approval.

**B. Requirements**

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the

Transmission Owner or Generator Owner identifies the Misoperation:

**R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. [*Violation Risk Factor: High*] [*Time Horizon: Same-day Operations*]

**R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. [*Violation Risk Factor: High*] [*Time Horizon: Same-day Operations*]

**R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.

**R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.

**R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. [*Violation Risk Factor: High*] [*Time Horizon: Same-day Operations*]

**R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.

**R2.3.2.** When FERAS is not available, then

**2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or

**2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.

**R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.

**R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

**R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Assessment*]

**R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to



WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
- R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

**C. Measures**

**Each measure below applies directly to the requirement by number.**

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
  - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
  - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
  - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
  - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
    - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
  - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
    - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.
  - M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
    - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

**R1**

|              |                 |             |               |
|--------------|-----------------|-------------|---------------|
| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|

**WECC Standard PRC-004-WECC-2 — Protection System and Remedial Action Scheme Misoperation**

|   |   |  |  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |
|---|---|--|--|

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.2.2 and R2.4**

| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|
|              |                 |             |               |

**WECC Standard PRC-004-WECC-2 — Protection System and Remedial Action Scheme Misoperation**

|  |   |   |  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |
|--|---|---|--|

**R3.1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| <b>Version</b> | <b>Date</b>    | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|----------------|--|------------------------|
| 1              | April 16, 2008 | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1 |                        |

**WECC Standard PRC-004-WECC-2 — Protection System and Remedial Action Scheme Misoperation**

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|   |                |   |  |
|---|----------------|---|--|
| 1 | April 21, 2011 | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |  |
| 2 | TBD            | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## **A. Introduction**

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-~~24~~
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

### **4. Applicability**

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
  - 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
  - 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** On the first day of the second quarter following applicable regulatory approval.

## **B. Requirements**

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
  - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
  - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the

Transmission Owner or Generator Owner identifies the Misoperation:

- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
  - R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
  - R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
  - R2.3.2.** When FERAS is not available, then
    - 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
    - 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
  - R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or
  - R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
- R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to

WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
- R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

### C. Measures

**Each measure below applies directly to the requirement by number.**

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
  - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
  - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
  - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
  - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
    - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
  - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
    - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
    - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.
  - M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
    - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.



**M2.4.2** Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

**M3.** Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

**M3.1** Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

**M3.2** Completion of repair or replacement of Protection System and/or RAS that misoperated.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1 Compliance Monitoring Responsibility**

Compliance Enforcement Authority

**1.2 Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

**1.2.1** The Performance-reset Period is one calendar month.

**1.3 Data Retention**

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

**R1**

|              |                 |             |               |
|--------------|-----------------|-------------|---------------|
| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|

**WECC Standard PRC-004-WECC-24 — Protection System and Remedial Action Scheme Misoperation**

|   |   |  |  |
|---|---|--|--|
| System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days. | System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days. | System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days. | System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days. |
|---|---|--|--|

**R2.1 and R2.2.1**

| <b>Lower</b>   | <b>Moderate</b>  | <b>High</b>   | <b>Severe</b>  |
|--|--|---|--|
| The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.3**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>  |
|---|---|---|--|
| The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours. | The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours. |

**R2.2.2 and R2.4**

| <b>Lower</b> | <b>Moderate</b> | <b>High</b> | <b>Severe</b> |
|--------------|-----------------|-------------|---------------|
|              |                 |             |               |

**WECC Standard PRC-004-WECC-24 — Protection System and Remedial Action Scheme Misoperation**

|  |   |   |  |
|--|---|---|--|
| The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days. | The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days. |
|--|---|---|--|

**R3.1**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days. |

**R3.2**

| <b>Lower</b>  | <b>Moderate</b>   | <b>High</b>   | <b>Severe</b>   |
|---|---|---|---|
| The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days. | The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion. |

**Version History** — Shows Approval History and Summary of Changes in the Action Field

| <b>Version</b> | <b>Date</b>    | <b>Action</b>  | <b>Change Tracking</b> |
|----------------|----------------|--|------------------------|
| 1              | April 16, 2008 | Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1 |                        |

**WECC Standard PRC-004-WECC-~~24~~ — Protection System and Remedial Action Scheme Misoperation**

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|               |                |   |  |
|---------------|----------------|---|--|
| 1             | April 21, 2011 | FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011) |  |
| <del>24</del> | TBD            | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** Protection System Maintenance
- 2. Number:** PRC-005-2(ii)
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
- 4. Applicability:**
  - 4.1. Functional Entities:**
    - 4.1.1** Transmission Owner
    - 4.1.2** Generator Owner
    - 4.1.3** Distribution Provider
  - 4.2. Facilities:**
    - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4** Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5** Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
- 5. Effective Date:** See Implementation Plan

**B. Requirements**

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**Component Type** - Any one of the five specific elements of the Protection System definition.

**Component** – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

**Unresolved Maintenance Issue** - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.  
  
For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)  
  
For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Enforcement Authority**
    - Regional Entity
  - 1.2. Compliance Monitoring and Enforcement Processes:**
    - Compliance Audit
    - Self-Certification
    - Spot Checking
    - Compliance Investigation
    - Self-Reporting
    - Complaint

**1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

**1.4. Additional Compliance Information**

None.



2. Violation Severity Levels

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|--------------------|---|---|--|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,</li> </ul> </li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,</li> <li style="text-align: center;">OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>   |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or   | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10   | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15   | The responsible entity failed to undertake efforts to correct greater   |

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| <b>Requirement Number</b> | <b>Lower VSL</b>                                | <b>Moderate VSL</b>                       | <b>High VSL</b>                           | <b>Severe VSL</b>                                 |
|---------------------------|---|---|---|---|
|                           | fewer identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(ii) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|       |                   |  |  |
|-------|-------------------|--|--|
| 1.1b  | May 9, 2012       | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).   |  |
| 2     | November 7, 2012  | Adopted by Board of Trustees   | Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2     | October 17, 2013  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.  |  |
| 2     | December 19, 2013 | FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. |  |
| 2(ii) | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS           |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 calendar years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |



| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3) |   |   |
|--|---|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |   |   |
| Component Attributes   | Maximum Maintenance Interval                  | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|  | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

Table 1-4(c)

**Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <b>Table 1-4(d)</b><br><b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).              |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

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| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RASs except as noted.</b> |                                   |   |
|--|-----------------------------------|---|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.   | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified | None.   |



| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                   | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.   | No periodic maintenance specified   | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 calendar years             | Verify that settings are as specified<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> Alarming for power supply failure (See Table 2).   | 12 calendar years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> Alarming for change of settings (See Table 2). | 12 calendar years            | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.  |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**Segment** – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

**Countable Event** – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(ii)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
  - 4.1. **Functional Entities:**
    - 4.1.1 Transmission Owner
    - 4.1.2 Generator Owner
    - 4.1.3 Distribution Provider
  - 4.2. **Facilities:**
    - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
    - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
5. **Effective Date:** See Implementation Plan

## B. Requirements

- R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**Component Type** - Any one of the five specific elements of the Protection System definition.

**Component** – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

**Unresolved Maintenance Issue** - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

## C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.
- For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)
- For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## D. Compliance

- 1. Compliance Monitoring Process**
- 1.1. Compliance Enforcement Authority**  
Regional Entity
- 1.2. Compliance Monitoring and Enforcement Processes:**  
Compliance Audit  
Self-Certification  
Spot Checking  
Compliance Investigation  
Self-Reporting  
Complaint



### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL   | Severe VSL   |
|--------------------|---|---|--|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>3) Maintained a Segment with less than 60 Components</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,</li> </ul> </li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    |  |  |   | <ul style="list-style-type: none"> <li>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,</li> <li style="text-align: center;">OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul>   |
| R3                 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4                 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.  |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or   | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10   | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15   | The responsible entity failed to undertake efforts to correct greater   |

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| Requirement Number | Lower VSL                                       | Moderate VSL                              | High VSL                                  | Severe VSL  |
|--------------------|---|---|---|---|
|                    | fewer identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | identified Unresolved Maintenance Issues. | than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(ii) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

**Version History**

| Version | Date               | Action  | Change Tracking                |
|---------|--------------------|---|--------------------------------|
| 0       | April 1, 2005      | Effective Date  | New                            |
| 1       | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a      | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a      | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a      | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a    | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b      | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b    | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|       |                   |  |  |
|-------|-------------------|--|--|
| 1.1b  | May 9, 2012       | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).   |  |
| 2     | November 7, 2012  | Adopted by Board of Trustees   | Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2     | October 17, 2013  | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.  |  |
| 2     | December 19, 2013 | FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. |  |
| 2(ii) | TBD               | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS           |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 calendar years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 calendar years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>1</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>1</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 calendar years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |



| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 calendar months            | Verify that the communications system is functional.   |
|   | 6 calendar years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 calendar years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 calendar years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 calendar years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval                   | Maintenance Activities   |
|---|--|--|
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months                              | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <b>Table 1-4(b)</b><br><b>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |   |   |
|---|---|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).                       |   |   |
| Component Attributes  | Maximum Maintenance Interval                  | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months                             | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|   | 6 Calendar Months                             | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|   | 18 Calendar Months                            | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul>   |
|   | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

Table 1-4(c)

**Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries  
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
|---|------------------------------|--|
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f). | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|   | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <b>Table 1-4(d)</b><br><b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).              |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|   | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|   | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                   | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                   | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                   | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                   | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                   | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                   | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                   | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |



| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RASs except as noted.</b> |                                   |   |
|--|-----------------------------------|---|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).  | 6 calendar years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.   | 12 calendar years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 calendar years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.   | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 calendar years             | <p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 calendar years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 calendar years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 calendar years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 calendar years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 calendar years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**Segment** – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

**Countable Event** – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

**A. Introduction**

- 1. Title:** Protection System and Automatic Reclosing Maintenance
- 2. Number:** PRC-005-3(ii)
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
  - 4.1. Functional Entities:**
    - 4.1.1** Transmission Owner
    - 4.1.2** Generator Owner
    - 4.1.3** Distribution Provider
  - 4.2. Facilities:**
    - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4** Protection Systems installed as a Remedial Action Schemes (RAS) for BES reliability.
    - 4.2.5** Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6** Automatic Reclosing<sup>1</sup>, including:
      - 4.2.6.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

**4.2.6.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.6.3** Automatic Reclosing applied as an integral part of a RAS specified in Section 4.2.4.

**5. Effective Date:** See Implementation Plan

**6. Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.



**B. Requirements**

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

**C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate

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monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Enforcement Authority**

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

##### **1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

##### **1.3. Evidence Retention**

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

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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

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**2. Violation Severity Levels**

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|--------------------|---|---|---|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>  | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.    |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|       |                  |   |  |
|-------|------------------|---|--|
| 1.1b  | May 9, 2012      | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).  |  |
| 2     | November 7, 2012 | Adopted by Board of Trustees  | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2     | October 17, 2013 | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing |  |
| 3     | November 7, 2013 | Adopted by the NERC Board of Trustees   | Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.              |
| 3(ii) | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS                               |



| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| <b>Table 1-1<br/>                     Component Type - Protective Relay<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b>   |   |   |
|--|---|---|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval<sup>2</sup></b> | <b>Maintenance Activities</b>   |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 Calendar Years                               | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 Calendar Months            | Verify that the communications system is functional.   |
|   | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br><br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| <b>Table 1-3</b><br><b>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b>  |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)          |                              |  |
|---|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

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**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

**Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).**

| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3) |                              |   |
|--|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |                              |   |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |   |   |
|---|---|---|
| Component Attributes  | Maximum Maintenance Interval                  | Maintenance Activities  |
|   | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |



| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| <p style="text-align: center;"><b>Table 1-4(d)</b><br/> <b>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage</b><br/> <b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b></p> <p style="text-align: center;">Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</p> |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|  | 18 Calendar Months           | Inspect: <ul style="list-style-type: none"> <li>Condition of non-battery based dc supply</li> </ul>  |
|  | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |

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| <b>Table 1-4(e)</b><br><b>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems</b>                              |  |                                   |
|--|--|-----------------------------------|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b>                | <b>Maintenance Activities</b>     |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

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| <b>Table 1-4(f)<br/>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems</b>  |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified   | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                     | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                     | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                     | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                     | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                     | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                     | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                     | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5<br/>                     Component Type - Control Circuitry Associated With Protective Functions<br/>                     Excluding distributed UFLS and distributed UVLS (see Table 3)</b> |                                     |   |
|--|-------------------------------------|---|
| <b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.</b>  |                                     |   |
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>   |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).  | 6 Calendar Years                    | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).              | 6 Calendar Years                    | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.<br>(See Table 4-2(b) for RAS which include Automatic Reclosing.)  | 12 Calendar Years                   | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.  | 12 Calendar Years                   | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).  | No periodic maintenance specified   | None.   |

| <b>Table 2 – Alarming Paths and Monitoring</b><br>In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements   |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.  | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | <p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 Calendar Years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 Calendar Years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |



| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing Relay   |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |

| <b>Table 4-2(a)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a RAS</b> |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a RAS.   | 12 Calendar Years                   | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of a RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)                                | No periodic maintenance specified   | None.  |

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| <b>Table 4-2(b)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of a RAS</b> |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of a RAS (regardless of any monitoring of the control circuitry).                        | 6 Calendar Years                    | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.                             |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of a RAS.   | 12 Calendar Years                   | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS. |
| Control circuitry associated with Automatic Reclosing that is an integral part of a RAS whose integrity is monitored and alarmed. (See Table 2)  | No periodic maintenance specified   | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

**A. Introduction**

- 1. Title:** Protection System and Automatic Reclosing Maintenance
- 2. Number:** PRC-005-3(ii)
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
  - 4.1. Functional Entities:**
    - 4.1.1** Transmission Owner
    - 4.1.2** Generator Owner
    - 4.1.3** Distribution Provider
  - 4.2. Facilities:**
    - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
    - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
    - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
    - 4.2.4** Protection Systems installed as a Remedial Action Schemes (RAS) for BES reliability.
    - 4.2.5** Protection Systems for generator Facilities that are part of the BES, including:
      - 4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
      - 4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.
      - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
      - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
    - 4.2.6** Automatic Reclosing<sup>1</sup>, including:
      - 4.2.6.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

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<sup>1</sup> Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

**4.2.6.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.6.3** Automatic Reclosing applied as an integral part of a RAS specified in Section 4.2.4.

**5. Effective Date:** See Implementation Plan

**6. Definitions Used in this Standard:** The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

**Component** – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

## **B. Requirements**

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning*]
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

## **C. Measures**

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate

monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

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

#### **1.2. Compliance Monitoring and Enforcement Processes:**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

#### **1.3. Evidence Retention**

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



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

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

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

### **1.4. Additional Compliance Information**

None.

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**2. Violation Severity Levels**

| Requirement Number | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|--------------------|---|---|---|--|
| R1                 | <p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> | <p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p> | <p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>  |
| R2                 | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>   | <p style="text-align: center;">NA</p>   | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>  | <p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> <li>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP</li> </ol> <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> <li>2) Failed to reduce Countable Events to no more than 4% within five years</li> </ol> <p style="text-align: center;">OR</p> |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|--------------------|--|--|---|--|
|                    |  |  |   | 3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: <ul style="list-style-type: none"> <li>• Annually update the list of Components,<br/>OR</li> <li>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br/>OR</li> <li>• Annually analyze the program activities and results for each Segment.</li> </ul> |
| R3                 | For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2. | For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.    |
| R4                 | For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific  | For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific   |

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| Requirement Number | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL  |
|--------------------|--|--|---|---|
|                    | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.  | Component Type in accordance with their performance-based PSMP.   | Component Type in accordance with their performance-based PSMP.   |
| R5                 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

**E. Regional Variances**

None

**F. Supplemental Reference Document**

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>   | <b>Change Tracking</b>         |
|----------------|--------------------|---|--------------------------------|
| 0              | April 1, 2005      | Effective Date  | New                            |
| 1              | December 1, 2005   | <ol style="list-style-type: none"> <li>1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>2. Added “periods” to items where appropriate.</li> <li>3. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05                       |
| 1a             | February 17, 2011  | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers  | Project 2009-17 interpretation |
| 1a             | February 17, 2011  | Adopted by Board of Trustees  |                                |
| 1a             | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)  |                                |
| 1.1a           | February 1, 2012   | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility  | Revision under Project 2010-07 |
| 1b             | February 3, 2012   | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.  | Project 2009-10 Interpretation |
| 1.1b           | April 23, 2012     | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.  | Revision under Project 2010-07 |

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|       |                  |   |  |
|-------|------------------|---|--|
| 1.1b  | May 9, 2012      | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).  |  |
| 2     | November 7, 2012 | Adopted by Board of Trustees  | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2     | October 17, 2013 | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing |  |
| 3     | November 7, 2013 | Adopted by the NERC Board of Trustees   | Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.              |
| 3(ii) | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS                               |

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.   | 6 Calendar Years                          | For all unmonitored relays: <ul style="list-style-type: none"> <li>• Verify that settings are as specified</li> </ul> For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (see Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> <li>• Alarming for power supply failure (see Table 2).</li> </ul> | 12 Calendar Years                         | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values.</li> </ul>  |

<sup>2</sup> For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)  |   |   |
|--|---|---|
| Component Attributes   | Maximum Maintenance Interval <sup>2</sup> | Maintenance Activities  |
| Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> <li>• Alarming for change of settings (See Table 2).</li> </ul> | 12 Calendar Years                         | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |



| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.  | 4 Calendar Months            | Verify that the communications system is functional.   |
|   | 6 Calendar Years             | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).   | 12 Calendar Years            | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following: <ul style="list-style-type: none"> <li>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System   |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3)   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Any voltage and current sensing devices not having monitoring attributes of the category below.  | 12 Calendar Years                 | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None.  |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply using <b>Vented Lead-Acid (VLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|   | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible</li> <li>• Physical condition of battery rack</li> </ul> |

**Table 1-4(a)**  
**Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries**  
**Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

| Component Attributes | Maximum Maintenance Interval                   | Maintenance Activities  |
|----------------------|--|---|
|                      | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3) |                              |   |
|--|------------------------------|---|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).  |                              |   |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities  |
| Protection System Station dc supply <b>with Valve Regulated Lead-Acid (VRLA) batteries</b> not having monitoring attributes of Table 1-4(f).   | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul>  |
|  | 6 Calendar Months            | Inspect: <ul style="list-style-type: none"> <li>• Condition of all individual units by measuring battery cell/unit internal ohmic values.</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Physical condition of battery rack</li> </ul> |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |   |   |
|---|---|---|
| Component Attributes  | Maximum Maintenance Interval                  | Maintenance Activities  |
|   | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Protection System Station dc supply <b>Nickel-Cadmium (NiCad) batteries</b> not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Electrolyte level</li> <li>• For unintentional grounds</li> </ul>  |
|  | 18 Calendar Months           | Verify: <ul style="list-style-type: none"> <li>• Float voltage of battery charger</li> <li>• Battery continuity</li> <li>• Battery terminal connection resistance</li> <li>• Battery intercell or unit-to-unit connection resistance</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• Cell condition of all individual battery cells.</li> <li>• Physical condition of battery rack</li> </ul> |
|  | 6 Calendar Years             | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.  |

| Table 1-4(d)<br>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage<br>Excluding distributed UFLS and distributed UVLS (see Table 3)         |                              |  |
|--|------------------------------|--|
| Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). |                              |  |
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).  | 4 Calendar Months            | Verify: <ul style="list-style-type: none"> <li>• Station dc supply voltage</li> </ul> Inspect: <ul style="list-style-type: none"> <li>• For unintentional grounds</li> </ul> |
|  | 18 Calendar Months           | Inspect:<br>Condition of non-battery based dc supply   |
|  | 6 Calendar Years             | Verify that the dc supply can perform as manufactured when ac power is not present.  |



| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems  |  |                                   |
|--|--|-----------------------------------|
| Component Attributes   | Maximum Maintenance Interval                       | Maintenance Activities            |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

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| <b>Table 1-4(f)</b><br><b>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems</b>  |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).  | No periodic maintenance specified   | No periodic verification of station dc supply voltage is required.   |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).  |                                     | No periodic inspection of the electrolyte level for each cell is required.   |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).  |                                     | No periodic inspection of unintentional dc grounds is required.  |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).  |                                     | No periodic verification of float voltage of battery charger is required.  |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).   |                                     | No periodic verification of the battery continuity is required.  |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).  |                                     | No periodic verification of the intercell and terminal connection resistance is required.  |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). |                                     | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).  |                                     | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.  |

| <b>Table 1-5</b><br><b>Component Type - Control Circuitry Associated With Protective Functions</b><br><b>Excluding distributed UFLS and distributed UVLS (see Table 3)</b><br><b>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.</b> |                                   |   |
|---|-----------------------------------|---|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities  |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.   |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).   | 6 Calendar Years                  | Verify electrical operation of electromechanical lockout devices.   |
| Unmonitored control circuitry associated with RAS.<br>(See Table 4-2(b) for RAS which include Automatic Reclosing.)   | 12 Calendar Years                 | Verify all paths of the control circuits essential for proper operation of the RAS.   |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.   | 12 Calendar Years                 | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).   | No periodic maintenance specified | None.   |

| <p align="center"><b>Table 2 – Alarming Paths and Monitoring</b></p> <p align="center">In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements</p>   |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| <p>Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.</p> <p>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.</p> | 12 Calendar Years                 | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| <p>Alarm Path with monitoring:</p> <p>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.</p>  | No periodic maintenance specified | None.  |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems   |                              |  |
|---|------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored protective relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | <p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate.</li> </ul> <p>For microprocessor relays:</p> <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Verify acceptable measurement of power system input values.</li> </ul> |
| <p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.</li> </ul> <p>Alarming for power supply failure (See Table 2).</p>   | 12 Calendar Years            | <p>Verify:</p> <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.</li> <li>• Acceptable measurement of power system input values</li> </ul>   |
| <p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> <li>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).</li> <li>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).</li> </ul> <p>Alarming for change of settings (See Table 2).</p> | 12 Calendar Years            | <p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>   |

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| <b>Table 3<br/>                     Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems</b>   |                                     |  |
|--|-------------------------------------|--|
| <b>Component Attributes</b>  | <b>Maximum Maintenance Interval</b> | <b>Maintenance Activities</b>  |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems.   | 12 Calendar Years                   | Verify that current and/or voltage signal values are provided to the protective relays.                                |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.   | 12 Calendar Years                   | Verify Protection System dc supply voltage.  |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).   | 12 Calendar Years                   | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.                            |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified   | None.  |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems.  | No periodic maintenance specified   | None.  |

| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing Relay   |                              |  |
|--|------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval | Maintenance Activities   |
| Any unmonitored reclosing relay not having all the monitoring attributes of a category below.  | 6 Calendar Years             | Verify that settings are as specified.<br>For non-microprocessor relays: <ul style="list-style-type: none"> <li>• Test and, if necessary calibrate</li> </ul> For microprocessor relays: <ul style="list-style-type: none"> <li>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul> |
| Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> <li>• Internal self-diagnosis and alarming (See Table 2).</li> <li>• Alarming for power supply failure (See Table 2).</li> </ul> | 12 Calendar Years            | Verify: <ul style="list-style-type: none"> <li>• Settings are as specified.</li> <li>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.</li> </ul>   |

| Table 4-2(a)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a RAS |                                   |  |
|---|-----------------------------------|--|
| Component Attributes  | Maximum Maintenance Interval      | Maintenance Activities   |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a RAS.  | 12 Calendar Years                 | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of a RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)           | No periodic maintenance specified | None.  |



| <b>Table 4-2(b)</b><br><b>Maintenance Activities and Intervals for Automatic Reclosing Components</b><br><b>Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of a RAS</b> |                                   |  |
|--|-----------------------------------|--|
| Component Attributes   | Maximum Maintenance Interval      | Maintenance Activities   |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of a RAS (regardless of any monitoring of the control circuitry).                        | 6 Calendar Years                  | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.                             |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of a RAS.   | 12 Calendar Years                 | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS. |
| Control circuitry associated with Automatic Reclosing that is an integral part of a RAS whose integrity is monitored and alarmed. (See Table 2)  | No periodic maintenance specified | None.  |

**PRC-005 — Attachment A**

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-1(i)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
  - 4.1. Planning Coordinators
  - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - 4.2.1 Transmission Owners
    - 4.2.2 Distribution Providers
  - 4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.
5. **(Proposed) Effective Date:**
  - 5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.
  - 5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1(i).

## B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [*VRF: Medium*][*Time Horizon: Long-term Planning*]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [*VRF: Medium*][*Time Horizon: Long-term Planning*]
  - 2.1. Those islands selected by applying the criteria in Requirement R1, and

- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme, and
      - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
  - R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
    - 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
    - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
    - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
      - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
      - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
      - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
  - R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]

- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
  - 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
  - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
  - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
  - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
  - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
  - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
  - 11.1.** The performance of the UFLS equipment,
  - 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance

with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

**R14.** Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

**14.1.** UFLS program, including a schedule for implementation

**14.2.** UFLS design assessment

**14.3.** Format and schedule of UFLS data submittal

### **C. Measures**

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a



UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity

#### **1.2. Data Retention**

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

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

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

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

Not applicable.

**2. Violation Severity Levels**

| R # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
| R1  | N/A       | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>   |
| R2  | N/A       | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p> |

| R #       | Lower VSL  | Moderate VSL  | High VSL   | Severe VSL   |
|-----------|--|---|--|--|
| <b>R3</b> | N/A  | <p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p> |
| <b>R4</b> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                        | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                     | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>   |

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----------|---|---|---|--|
|           |   |   |   | The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2                                 |
| <b>R5</b> | N/A   | N/A   | N/A   | The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5. |
| <b>R6</b> | N/A   | N/A   | N/A   | The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.  |
| <b>R7</b> | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.<br><br>OR   |

| R #        | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL   |
|------------|---|--|---|--|
|            |   |  |   | The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.   |
| <b>R8</b>  | The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.                | The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. |
| <b>R9</b>  | The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. | The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   | The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.                  | The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   |
| <b>R10</b> | The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching  | The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching  | The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching   | The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,   |

| R #        | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|------------|--|---|---|--|
|            | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission   | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  | Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  |
| <b>R11</b> | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation. | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation. | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.<br><br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.<br><br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.<br><br>OR |

| R #        | Lower VSL | Moderate VSL   | High VSL   | Severe VSL   |
|------------|-----------|--|--|--|
|            |           |  | specified in Requirement R11, Parts 11.1 or 11.2.  | The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.  |
| <b>R12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.<br><br>OR<br>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies. |
| <b>R13</b> | N/A       | N/A  | N/A  | The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency  |



| R #        | Lower VSL | Moderate VSL | High VSL | Severe VSL   |
|------------|-----------|--------------|----------|--|
|            |           |              |          | excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13   |
| <b>R14</b> | N/A       | N/A          | N/A      | The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3. |

## E. Regional Variances

### E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

- E.A.3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s).  
*[VRF: High][Time Horizon: Long-term Planning]*
- E.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- E.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
- EA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES
- EA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES
- EA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.
- E.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*
- E.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1A, and

**E.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 2A, and

**E.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**M.E.A.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

**M.E.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

| E #        | Lower VSL | Moderate VSL  | High VSL   | Severe VSL  |
|------------|-----------|---|--|---|
| <b>EA3</b> | N/A       | The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to develop a UFLS program.  |
| <b>EA4</b> | N/A       | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3.<br><br>OR<br><br>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 |

## **E.B. Regional Variance for the Western Electricity Coordinating Council**

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

**E.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.1.** Those islands selected by applying the criteria in Requirement E.B.1, and

**E.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme.

**EB.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

**E.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**E.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

**E.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**E.B.11.1.** The performance of the UFLS equipment,

**E.B.11.2** The effectiveness of the UFLS program

**E.B.12.** Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

**M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

**M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

**M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

**M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

**M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

**M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

| E #          | Lower VSL | Moderate VSL   | High VSL  | Severe VSL   |
|--------------|-----------|--|---|--|
| <b>E.B.1</b> | N/A       | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p> |
| <b>E.B.2</b> | N/A       | N/A  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>   |



| E #          | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|--------------|---|--|--|--|
|              |   |  |  | <p>The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.</p>  |
| <b>E.B.3</b> | N/A   | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p> | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p> | <p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions</p> <p>OR</p> <p>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.</p> |
| <b>E.B.4</b> | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p> | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>                      | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>                      | <p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>  |

| E #           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|---------------|---|--|--|--|
|               | <p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>  | <p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p> |
| <b>E.B.11</b> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>   |

| E #           | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|---------------|-----------|---|---|--|
|               |           |   | <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p> | <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> |
| <b>E.B.12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design   | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design  |

| E # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
|     |           | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p> |

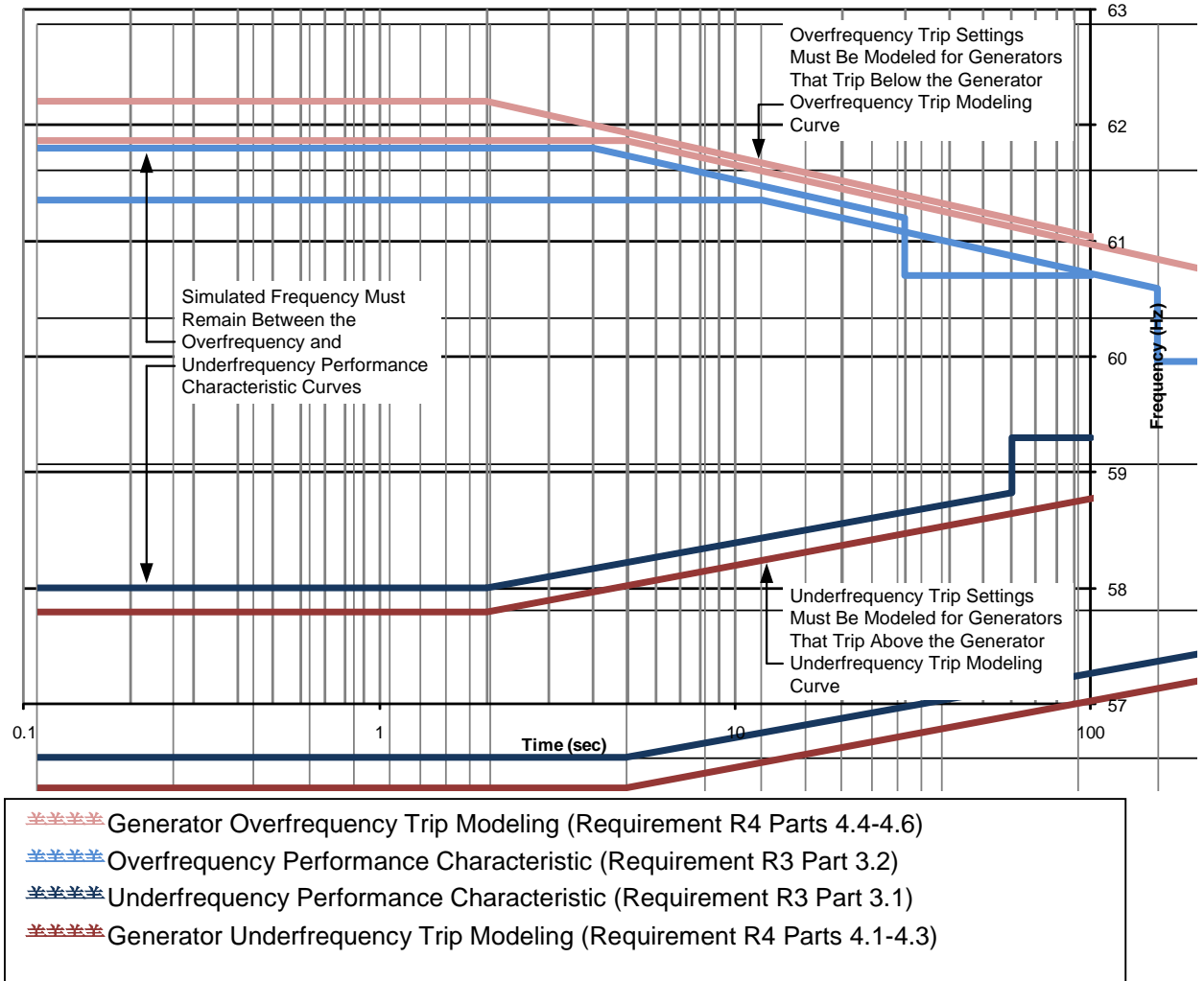
## Associated Documents

### Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 1       | May 25, 2010     | Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.   |  |
| 1       | November 4, 2010 | Adopted by the Board of Trustees   |  |
| 1       | May 7, 2012      | FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)   |  |
| 1       | November 9, 2012 | FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8. |  |
| 1(i)    | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## PRC-006-1(i) – Attachment 1

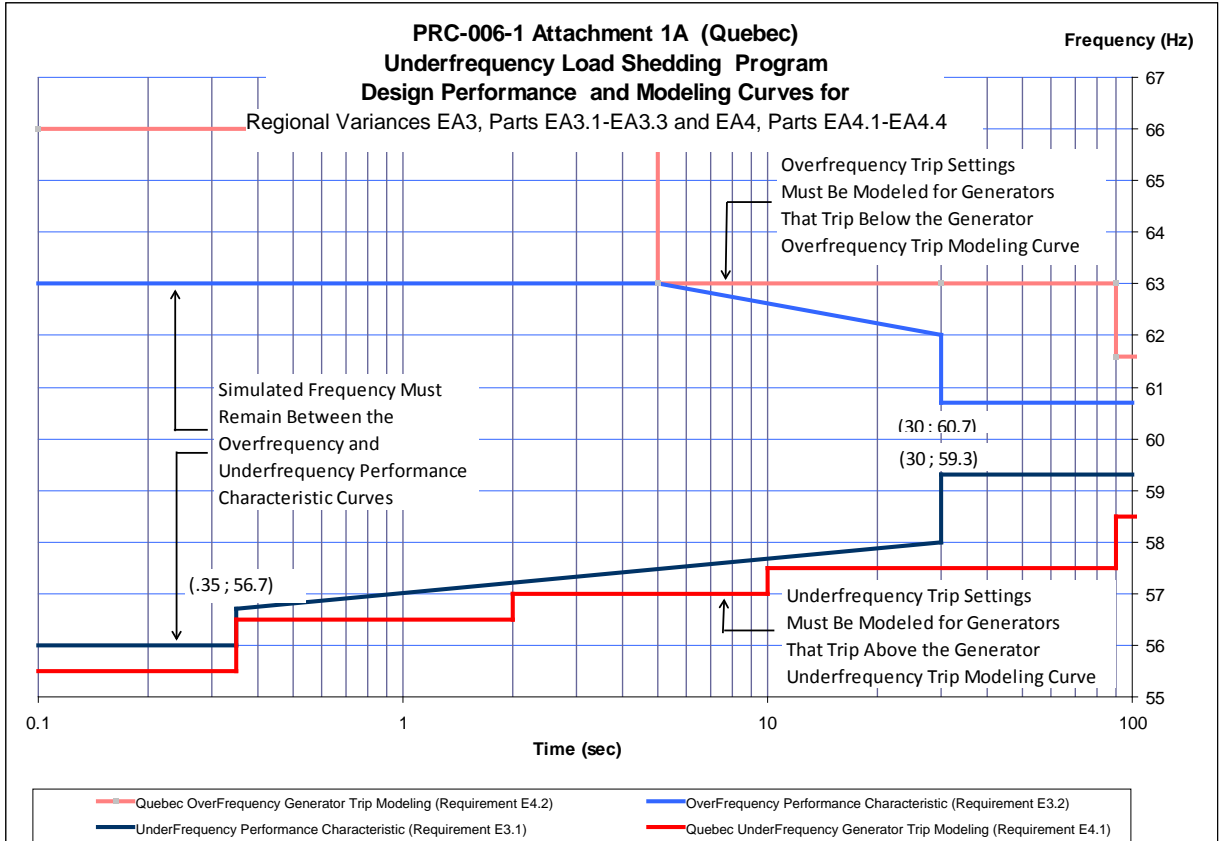
### Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



#### Curve Definitions

| Generator Overfrequency Trip Modeling |  | Overfrequency Performance Characteristic |  |                       |
|---------------------------------------|--|--|--|-----------------------|
| $t \leq 2 \text{ s}$                  | $t > 2 \text{ s}$                      | $t \leq 4 \text{ s}$                     | $4 \text{ s} < t \leq 30 \text{ s}$    | $t > 30 \text{ s}$    |
| $f = 62.2 \text{ Hz}$                 | $f = -0.686\log(t) + 62.41 \text{ Hz}$ | $f = 61.8 \text{ Hz}$                    | $f = -0.686\log(t) + 62.21 \text{ Hz}$ | $f = 60.7 \text{ Hz}$ |

| Generator Underfrequency Trip Modeling |                                       | Underfrequency Performance Characteristic |                                       |                       |
|--|---------------------------------------|---|---------------------------------------|-----------------------|
| $t \leq 2 \text{ s}$                   | $t > 2 \text{ s}$                     | $t \leq 2 \text{ s}$                      | $2 \text{ s} < t \leq 60 \text{ s}$   | $t > 60 \text{ s}$    |
| $f = 57.8 \text{ Hz}$                  | $f = 0.575\log(t) + 57.63 \text{ Hz}$ | $f = 58.0 \text{ Hz}$                     | $f = 0.575\log(t) + 57.83 \text{ Hz}$ | $f = 59.3 \text{ Hz}$ |



## A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-1(i)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
  - 4.1. Planning Coordinators
  - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - 4.2.1 Transmission Owners
    - 4.2.2 Distribution Providers
  - 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.
5. **(Proposed) Effective Date:**
  - 5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.
  - 5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1(i).

## B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [*VRF: Medium*][*Time Horizon: Long-term Planning*]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [*VRF: Medium*][*Time Horizon: Long-term Planning*]
  - 2.1. Those islands selected by applying the criteria in Requirement R1, and



- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme, and
  - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
- 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
  - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
    - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
    - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
    - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]

- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
  - 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
  - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
  - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
  - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
  - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
  - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
  - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
  - 11.1.** The performance of the UFLS equipment,
  - 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance

with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

**R14.** Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

**14.1.** UFLS program, including a schedule for implementation

**14.2.** UFLS design assessment

**14.3.** Format and schedule of UFLS data submittal

### **C. Measures**

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a

UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Enforcement Authority**

Regional Entity

#### **1.2. Data Retention**

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

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

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

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

Not applicable.

**2. Violation Severity Levels**

| R # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
| R1  | N/A       | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p> | <p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>   |
| R2  | N/A       | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>   | <p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p> |



| R #       | Lower VSL  | Moderate VSL   | High VSL  | Severe VSL   |
|-----------|--|--|---|--|
| <b>R3</b> | N/A  | <p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p> | <p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p> |
| <b>R4</b> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                         | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>                      | <p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>   |

| R #       | Lower VSL   | Moderate VSL  | High VSL  | Severe VSL   |
|-----------|---|---|---|--|
|           |   |   |   | The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2                                 |
| <b>R5</b> | N/A   | N/A   | N/A   | The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5. |
| <b>R6</b> | N/A   | N/A   | N/A   | The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.  |
| <b>R7</b> | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request. | The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.<br><br>OR   |

| R #        | Lower VSL   | Moderate VSL   | High VSL  | Severe VSL   |
|------------|---|--|---|--|
|            |   |  |   | The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.   |
| <b>R8</b>  | The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.                | The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. | The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.<br><br>OR<br><br>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. |
| <b>R9</b>  | The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. | The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   | The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.                  | The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.   |
| <b>R10</b> | The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching  | The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching  | The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching   | The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,   |

| R #        | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL   |
|------------|--|---|---|--|
|            | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission   | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  | of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  | Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission  |
| <b>R11</b> | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation. | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation. | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.<br><br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as | The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.<br><br>OR<br>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.<br><br>OR |

| R #        | Lower VSL | Moderate VSL   | High VSL   | Severe VSL   |
|------------|-----------|--|--|--|
|            |           |  | specified in Requirement R11, Parts 11.1 or 11.2.  | The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.  |
| <b>R12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.<br><br>OR<br>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies. |
| <b>R13</b> | N/A       | N/A  | N/A  | The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency  |

| R #        | Lower VSL | Moderate VSL | High VSL | Severe VSL   |
|------------|-----------|--------------|----------|--|
|            |           |              |          | excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13   |
| <b>R14</b> | N/A       | N/A          | N/A      | The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3. |

## E. Regional Variances

### E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

**E.A.3.** Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).  
*[VRF: High][Time Horizon: Long-term Planning]*

**E.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.A.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**EA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

**EA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

**EA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

**E.A.4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

**E.A.4.1** Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1A, and

**E.A.4.2** Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 2A, and

**E.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

**M.E.A.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

**M.E.A.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.



| E #        | Lower VSL | Moderate VSL  | High VSL   | Severe VSL  |
|------------|-----------|---|--|---|
| <b>EA3</b> | N/A       | The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions   | The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to develop a UFLS program.  |
| <b>EA4</b> | N/A       | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3. | The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3.<br><br>OR<br><br>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 |

## **E.B. Regional Variance for the Western Electricity Coordinating Council**

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

**E.B.1.** Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.** Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

**E.B.2.1.** Those islands selected by applying the criteria in Requirement E.B.1, and

**E.B.2.2.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme.

**EB.3.** Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance =  $[(\text{load} - \text{actual generation output}) / (\text{load})]$ , of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

**E.B.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(i) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

**E.B.3.3.** Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

**E.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

**E.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(i) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(i) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

**E.B.11.1.** The performance of the UFLS equipment,

**E.B.11.2** The effectiveness of the UFLS program

**E.B.12.** Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

- M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.
- M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.
- M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.
- M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.
- M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.
- M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

| E #   | Lower VSL | Moderate VSL   | High VSL  | Severe VSL   |
|-------|-----------|--|---|--|
| E.B.1 | N/A       | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> | <p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p> |
| E.B.2 | N/A       | N/A  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>  | <p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>   |

| E #          | Lower VSL  | Moderate VSL  | High VSL  | Severe VSL  |
|--------------|--|---|---|---|
|              |  |   |   | The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.  |
| <b>E.B.3</b> | N/A  | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions | The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions<br><br>OR<br><br>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area. |
| <b>E.B.4</b> | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island                      | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island                      | The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island  |

| E #           | Lower VSL   | Moderate VSL   | High VSL   | Severe VSL   |
|---------------|---|--|--|--|
|               | <p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>  | <p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>   | <p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p> |
| <b>E.B.11</b> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> | <p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>   |

| E #           | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|---------------|-----------|---|---|--|
|               |           |   | <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p> | <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> |
| <b>E.B.12</b> | N/A       | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design   | The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design  |



| E # | Lower VSL | Moderate VSL  | High VSL  | Severe VSL   |
|-----|-----------|---|---|--|
|     |           | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p> | <p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p> |

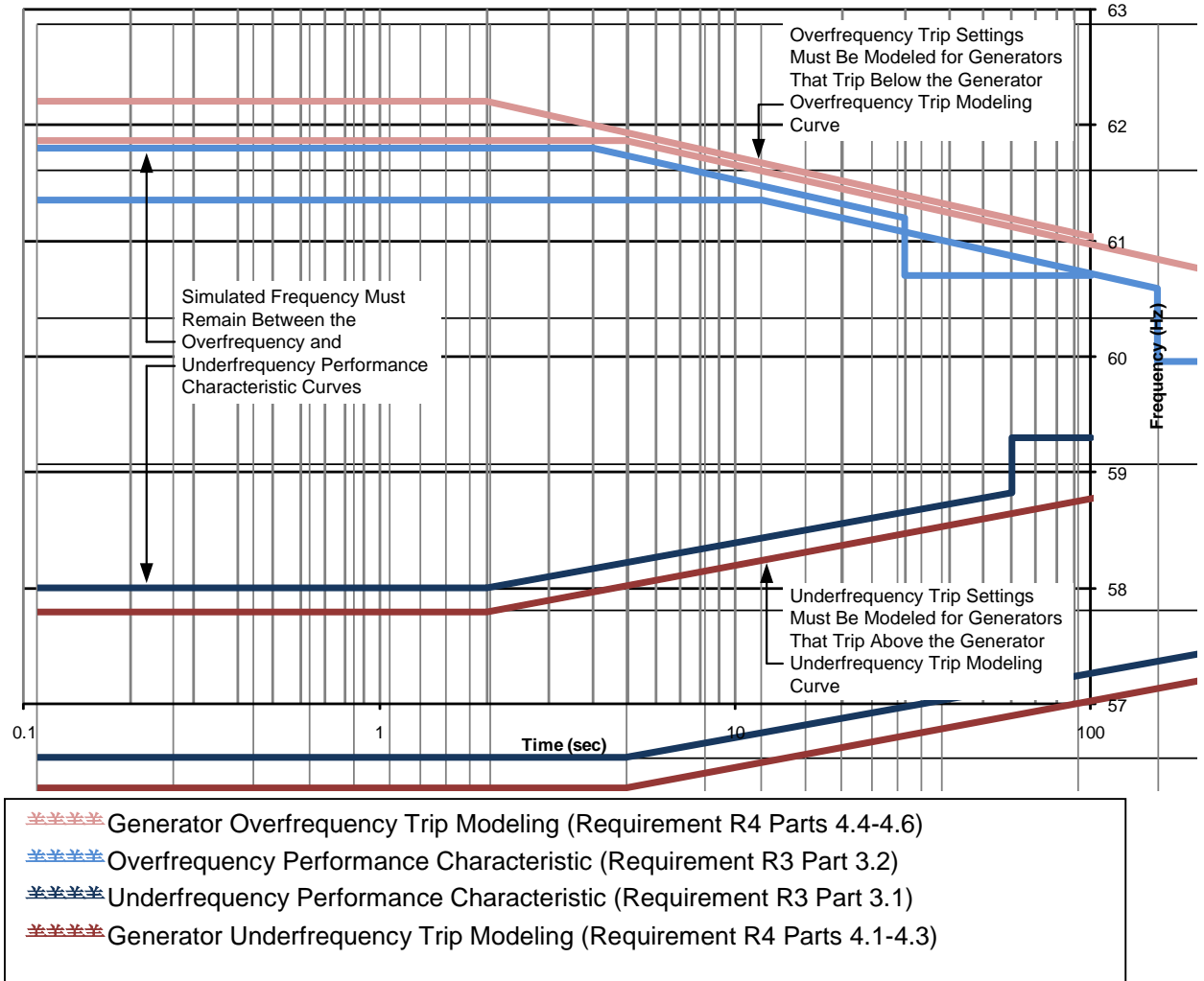
**Associated Documents**

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>  | <b>Change Tracking</b>   |
|----------------|------------------|--|--|
| 1              | May 25, 2010     | Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.   |  |
| 1              | November 4, 2010 | Adopted by the Board of Trustees   |  |
| 1              | May 7, 2012      | FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)   |  |
| 1              | November 9, 2012 | FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8. |  |
| 1(i)           | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## PRC-006-1(i) – Attachment 1

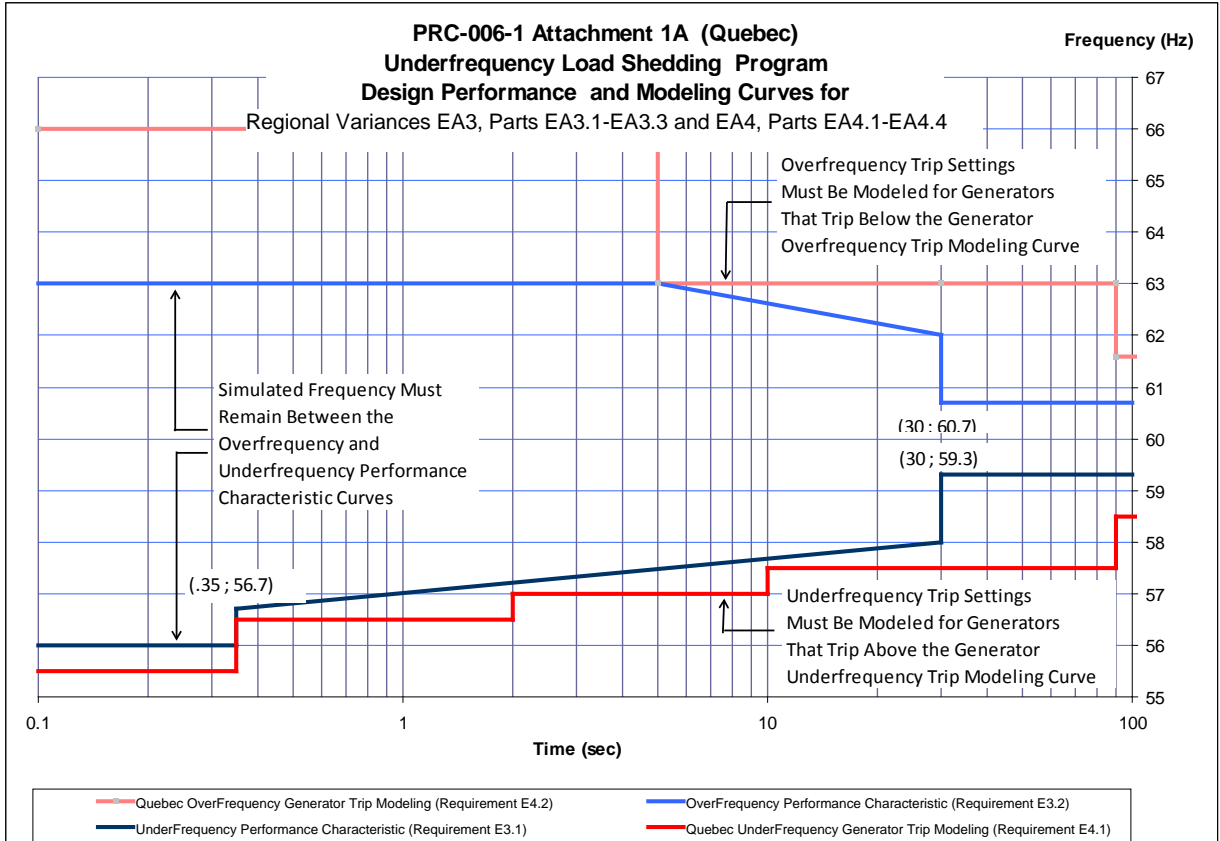
### Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



#### Curve Definitions

| Generator Overfrequency Trip Modeling |  | Overfrequency Performance Characteristic |  |                       |
|---------------------------------------|--|--|--|-----------------------|
| $t \leq 2 \text{ s}$                  | $t > 2 \text{ s}$                      | $t \leq 4 \text{ s}$                     | $4 \text{ s} < t \leq 30 \text{ s}$    | $t > 30 \text{ s}$    |
| $f = 62.2 \text{ Hz}$                 | $f = -0.686\log(t) + 62.41 \text{ Hz}$ | $f = 61.8 \text{ Hz}$                    | $f = -0.686\log(t) + 62.21 \text{ Hz}$ | $f = 60.7 \text{ Hz}$ |

| Generator Underfrequency Trip Modeling |                                       | Underfrequency Performance Characteristic |                                       |                       |
|--|---------------------------------------|---|---------------------------------------|-----------------------|
| $t \leq 2 \text{ s}$                   | $t > 2 \text{ s}$                     | $t \leq 2 \text{ s}$                      | $2 \text{ s} < t \leq 60 \text{ s}$   | $t > 60 \text{ s}$    |
| $f = 57.8 \text{ Hz}$                  | $f = 0.575\log(t) + 57.63 \text{ Hz}$ | $f = 58.0 \text{ Hz}$                     | $f = 0.575\log(t) + 57.83 \text{ Hz}$ | $f = 59.3 \text{ Hz}$ |



### A. Introduction

1. **Title:** Remedial Action Scheme Review Procedure
2. **Number:** PRC-012-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

### B. Requirements

- R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:
  - R1.1. Description of the process for submitting a proposed RAS for Regional Reliability Organization review.
  - R1.2. Requirements to provide data that describes design, operation, and modeling of a RAS.
  - R1.3. Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4. Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5. Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6. Regional Reliability Organization definition of misoperation.
  - R1.7. Requirements for analysis and documentation of corrective action plans for all RAS misoperations.
  - R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9. Determination, as appropriate, of maintenance and testing requirements.
- R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**C. Measures**

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-1\_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-1\_R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-1\_R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-1\_R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-1\_R1.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| <b>Version</b> | <b>Date</b>   | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|---------------|---------------------------------------|--|
| 0              | April 1, 2005 | Effective Date                        | New  |
| 1              | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** Remedial Action Scheme Review Procedure
- 2. Number:** PRC-012-~~10~~
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Regional Reliability Organization
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:
  - R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review.
  - R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS.
  - R1.3.** Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
  - R1.4.** Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
  - R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
  - R1.6.** Regional Reliability Organization definition of misoperation.
  - R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations.
  - R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
  - R1.9.** Determination, as appropriate, of maintenance and testing requirements.
- R2.** The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**C. Measures**

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-~~10~~\_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-~~10~~\_R1.

**2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-~~10~~\_R1.

**2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-~~10~~\_R1.

**2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-~~10~~\_R1.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| Version       | Date          | Action                                | Change Tracking  |
|---------------|---------------|---------------------------------------|--|
| 0             | April 1, 2005 | Effective Date                        | New  |
| <del>10</del> | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



## A. Introduction

1. **Title:** Remedial Action Scheme Database.
2. **Number:** PRC-013-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

## B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,
  - R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

## C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-1\_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
  - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
  - 1.3. **Data Retention**

None specified.
  - 1.4. **Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-1\_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-1\_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-1\_R1.

**E. Regional Differences**

- 1.** None identified.

**Version History**

| <b>Version</b> | <b>Date</b>   | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|---------------|---------------------------------------|--|
| 0              | April 1, 2005 | Effective Dave                        | New  |
| 1              | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|                |               |                                       |  |
|                |               |                                       |  |

## A. Introduction

1. **Title:** Remedial Action Scheme Database.
2. **Number:** PRC-013-~~10~~
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

## B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:
  - R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,
  - R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and
  - R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

## C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-~~10~~\_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
  - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
  - 1.3. **Data Retention**

None specified.
  - 1.4. **Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-~~10~~\_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-~~10~~\_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-~~10~~\_R1.

**E. Regional Differences**

- 1. None identified.

**Version History**

| Version       | Date          | Action                                | Change Tracking  |
|---------------|---------------|---------------------------------------|--|
| 0             | April 1, 2005 | Effective Dave                        | New  |
| <del>10</del> | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|               |               |                                       |  |
|               |               |                                       |  |

**A. Introduction**

- 1. Title:** Remedial Action Scheme Assessment
- 2. Number:** PRC-014-1
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1. Regional Reliability Organization**
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3.** The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:
  - R3.1.** Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems.
  - R3.5.** Provide corrective action plans for non-compliant RAS.

**C. Measures**

- M1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3.** The Regional Reliability Organization's documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-1\_R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-1\_R3.

**2.2. Level 2:** The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-1\_3.

**2.3. Level 3:** The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-1\_R3.

**2.4. Level 4:** The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-1\_R3 or was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 1       | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|         |               |                                       |  |
|         |               |                                       |  |

## A. Introduction

1. **Title:** Remedial Action Scheme Assessment
2. **Number:** PRC-014-~~10~~
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

## B. Requirements

- R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:
  - R3.1. Identification of group conducting the assessment and the date the assessment was performed.
  - R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
  - R3.3. Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
  - R3.4. Discussion of any coordination problems found between a RAS and other protection and control systems.
  - R3.5. Provide corrective action plans for non-compliant RAS.

## C. Measures

- M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3. The Regional Reliability Organization's documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-~~10~~\_R3.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: NERC.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-~~10~~\_R3.

**2.2. Level 2:** The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-~~10~~\_3.

**2.3. Level 3:** The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-~~10~~\_R3.

**2.4. Level 4:** The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-~~10~~\_R3 or was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version       | Date          | Action                                | Change Tracking  |
|---------------|---------------|---------------------------------------|--|
| 0             | April 1, 2005 | Effective Date                        | New  |
| <del>10</del> | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
|               |               |                                       |  |
|               |               |                                       |  |



### A. Introduction

1. **Title:** Remedial Action Scheme Data and Documentation
2. **Number:** PRC-015-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS
  - 4.2. Generator Owner that owns a RAS
  - 4.3. Distribution Provider that owns a RAS
5. **Effective Date:** April 1, 2005

### B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1\_R1 prior to being placed in service.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

### C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-1\_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1\_R1 prior to being placed in service.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

**2.2. Level 2:** RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-1\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-1\_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-1\_R1.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date          | Action                                | Change Tracking  |
|---------|---------------|---------------------------------------|--|
| 0       | April 1, 2005 | Effective Date                        | New  |
| 1       | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** Remedial Action Scheme Data and Documentation
- 2. Number:** PRC-015-10
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Transmission Owner that owns a RAS
  - 4.2.** Generator Owner that owns a RAS
  - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-10 R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-10\_R1 prior to being placed in service.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

**C. Measures**

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-10\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-10\_R1 prior to being placed in service.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days).

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

**2.2. Level 2:** RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-~~10~~\_R1.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-~~10~~\_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-~~10~~\_R1.

**E. Regional Differences**

1. None identified.

**Version History**

| Version       | Date          | Action                                | Change Tracking  |
|---------------|---------------|---------------------------------------|--|
| 0             | April 1, 2005 | Effective Date                        | New  |
| <del>10</del> | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### A. Introduction

1. **Title: Remedial Action Scheme Misoperations**
2. **Number:** PRC-016-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS.
  - 4.2. Generator Owner that owns a RAS.
  - 4.3. Distribution Provider that owns a RAS.
5. **Effective Date:** May 13, 2009

### B. Requirements

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1\_R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

### C. Measures

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

## Standard PRC-016-1 — Remedial Action Scheme Misoperations

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### 1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

**2.2. Level 2:** Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

**2.3. Level 3:** Documentation of RAS misoperations and corrective actions is incomplete.

**2.4. Level 4:** No documentation of RAS misoperations or corrective actions.

## E. Regional Differences

None identified.

## Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 0       | April 1, 2005    | Effective Date   | New  |
| 0       | February 8, 2005 | Adopted by NERC Board of Trustees                                    | New  |
| 0       | July 3, 2007     | Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.” | Errata   |
| 0.1     | October 29, 2008 | BOT adopted errata changes; updated version number to “0.1”          | Errata   |
| 0.1     | May 13, 2009     | FERC Approved – Updated Effective Date                               | Revised  |
| 1       | TBD              | Adopted by the NERC Board of Trustees                                | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### A. Introduction

1. **Title: Remedial Action Scheme Misoperations**
2. **Number:** PRC-016-~~10.1~~
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
  - 4.1. Transmission Owner that owns a RAS.
  - 4.2. Generator Owner that owns a RAS.
  - 4.3. Distribution Provider that owns a RAS.
5. **Effective Date:** May 13, 2009

### B. Requirements

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-~~10~~\_R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

### C. Measures

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-~~10~~\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

**2.2. Level 2:** Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

**2.3. Level 3:** Documentation of RAS misoperations and corrective actions is incomplete.

**2.4. Level 4:** No documentation of RAS misoperations or corrective actions.

**E. Regional Differences**

None identified.

**Version History**

| Version         | Date             | Action   | Change Tracking  |
|-----------------|------------------|--|--|
| 0               | April 1, 2005    | Effective Date   | New  |
| 0               | February 8, 2005 | Adopted by NERC Board of Trustees                                    | New  |
| 0               | July 3, 2007     | Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.” | Errata   |
| 0.1             | October 29, 2008 | BOT adopted errata changes; updated version number to “0.1”          | Errata   |
| 0.1             | May 13, 2009     | FERC Approved – Updated Effective Date                               | Revised  |
| <del>10.1</del> | TBD              | Adopted by the NERC Board of Trustees                                | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



**A. Introduction**

- 1. Title:** Remedial Action Scheme Maintenance and Testing
- 2. Number:** PRC-017-1
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Transmission Owner that owns a RAS
  - 4.2.** Generator Owner that owns a RAS
  - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1.** RAS identification shall include but is not limited to:
    - R1.1.1.** Relays.
    - R1.1.2.** Instrument transformers.
    - R1.1.3.** Communications systems, where appropriate.
    - R1.1.4.** Batteries.
  - R1.2.** Documentation of maintenance and testing intervals and their basis.
  - R1.3.** Summary of testing procedure.
  - R1.4.** Schedule for system testing.
  - R1.5.** Schedule for system maintenance.
  - R1.6.** Date last tested/maintained.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**C. Measures**

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-1\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

**1.2. Compliance Monitoring Period and Reset Timeframe**

Compliance Monitor: Regional Reliability Organization.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>   | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|---------------|---------------------------------------|--|
| 0              | April 1, 2005 | Effective Date                        | New  |
| 1              | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** Remedial Action Scheme Maintenance and Testing
- 2. Number:** PRC-017-10
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
  - 4.1.** Transmission Owner that owns a RAS
  - 4.2.** Generator Owner that owns a RAS
  - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** April 1, 2005

**B. Requirements**

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
  - R1.1.** RAS identification shall include but is not limited to:
    - R1.1.1.** Relays.
    - R1.1.2.** Instrument transformers.
    - R1.1.3.** Communications systems, where appropriate.
    - R1.1.4.** Batteries.
  - R1.2.** Documentation of maintenance and testing intervals and their basis.
  - R1.3.** Summary of testing procedure.
  - R1.4.** Schedule for system testing.
  - R1.5.** Schedule for system maintenance.
  - R1.6.** Date last tested/maintained.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**C. Measures**

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-10\_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

**Timeframe:**

On request (30 calendar days.)

**1.2. Compliance Monitoring Period and Reset Timeframe**

Compliance Monitor: Regional Reliability Organization.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

**2.2. Level 2:** Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

**2.3. Level 3:** Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

**2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

**E. Regional Differences**

1. None identified.

**Version History**

| Version       | Date          | Action                                | Change Tracking  |
|---------------|---------------|---------------------------------------|--|
| 0             | April 1, 2005 | Effective Date                        | New  |
| <del>10</del> | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

## A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Database
2. **Number:** PRC-020-2
3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
4. **Applicability**
  - 4.1. Regional Reliability Organization with entities that own or operate a UVLS program.
5. **Effective Date:** May 1, 2006

## B. Requirements

- R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
  - R1.1. Owner and operator of the UVLS program.
  - R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.3. Corresponding voltage set points and overall scheme clearing times.
  - R1.4. Time delay from initiation to trip signal.
  - R1.5. Breaker operating times.
  - R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

## C. Measures

- M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

NERC
  - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. **Data Retention**

## Standard PRC-020-2 — Under-Voltage Load Shedding Program Database

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

2.1. **Level 1:** Did not update its UVLS database annually.

2.2. **Level 2:** UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Did not provide information from its UVLS program database.

## E. Regional Differences

None identified.

## Version History

| Version | Date     | Action   | Change Tracking  |
|---------|----------|--|--|
| 1       | 12/01/05 | <ol style="list-style-type: none"><li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li><li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li><li>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li><li>4. Added or removed “periods” where appropriate.</li><li>5. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li></ol> | 01/20/06   |
| 2       | TBD      | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

- 1. Title:** Under-Voltage Load Shedding Program Database
- 2. Number:** PRC-020-~~21~~
- 3. Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
- 4. Applicability**
  - 4.1.** Regional Reliability Organization with entities that own or operate a UVLS program.
- 5. Effective Date:** May 1, 2006

**B. Requirements**

- R1.** The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
  - R1.1.** Owner and operator of the UVLS program.
  - R1.2.** Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.3.** Corresponding voltage set points and overall scheme clearing times.
  - R1.4.** Time delay from initiation to trip signal.
  - R1.5.** Breaker operating times.
  - R1.6.** Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2.** The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

**C. Measures**

- M1.** The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2.** The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

**D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

NERC
  - 1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. Data Retention**

## Standard PRC-020-~~21~~ — Under-Voltage Load Shedding Program Database

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

2.1. **Level 1:** Did not update its UVLS database annually.

2.2. **Level 2:** UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Did not provide information from its UVLS program database.

## E. Regional Differences

None identified.

## Version History

| Version       | Date     | Action  | Change Tracking  |
|---------------|----------|---|--|
| 1             | 12/01/05 | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—).”</li> <li>3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>4. Added or removed “periods” where appropriate.</li> <li>5. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/06   |
| <del>21</del> | TBD      | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



### A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Data
2. **Number:** PRC-021-2
3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. **Applicability**
  - 4.1. Transmission Owner that owns a UVLS program.
  - 4.2. Distribution Provider that owns a UVLS program.
5. **Effective Date:** August 1, 2006

### B. Requirements

- R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
  - R1.1. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.2. Corresponding voltage set points and overall scheme clearing times.
  - R1.3. Time delay from initiation to trip signal.
  - R1.4. Breaker operating times.
  - R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

### C. Measures

- M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

### D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.
  - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. **Data Retention**

## Standard PRC-021-2 — Under-Voltage Load Shedding Program Data

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Did not update its UVLS data annually.

**2.2. Level 2:** UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

**2.3. Level 3:** UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

**2.4. Level 4:** Did not provide any UVLS data.

## E. Regional Differences

None identified.

## Version History

| Version | Date     | Action   | Change Tracking  |
|---------|----------|--|--|
| 1       | 12/01/05 | <ol style="list-style-type: none"><li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li><li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li><li>3. Added heading above table “Future Development Plan.”</li><li>4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li><li>5. Added or removed “periods” where appropriate.</li><li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li></ol> | 01/20/05   |
| 2       | TBD      | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**A. Introduction**

1. **Title:** Under-Voltage Load Shedding Program Data
2. **Number:** PRC-021-~~21~~
3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. **Applicability**
  - 4.1. Transmission Owner that owns a UVLS program.
  - 4.2. Distribution Provider that owns a UVLS program.
5. **Effective Date:** August 1, 2006

**B. Requirements**

- R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
  - R1.1. Size and location of customer load, or percent of connected load, to be interrupted.
  - R1.2. Corresponding voltage set points and overall scheme clearing times.
  - R1.3. Time delay from initiation to trip signal.
  - R1.4. Breaker operating times.
  - R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

**C. Measures**

- M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

**D. Compliance**

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.
  - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
  - 1.3. **Data Retention**

## Standard PRC-021-~~21~~ — Under-Voltage Load Shedding Program Data

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

### 1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

## 2. Levels of Non-Compliance

**2.1. Level 1:** Did not update its UVLS data annually.

**2.2. Level 2:** UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

**2.3. Level 3:** UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

**2.4. Level 4:** Did not provide any UVLS data.

## E. Regional Differences

None identified.

## Version History

| Version       | Date     | Action  | Change Tracking  |
|---------------|----------|---|--|
| 1             | 12/01/05 | <ol style="list-style-type: none"> <li>1. Removed comma after 2004 in “Development Steps Completed,” #1.</li> <li>2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”</li> <li>3. Added heading above table “Future Development Plan.”</li> <li>4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate.</li> <li>5. Added or removed “periods” where appropriate.</li> <li>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.</li> </ol> | 01/20/05   |
| <del>21</del> | TBD      | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### A. Introduction

#### 1. Title: Transmission Relay Loadability

#### 2. Number: PRC-023-2(i)

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

#### 4. Applicability

##### 4.1. Functional Entity

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(i) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2(i) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(i) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinators

##### 4.2. Circuits

##### 4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

##### 4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

#### 5. Effective Dates

The effective dates of the requirements in the PRC-023-2(i) standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Applicability  | Effective Date   |   |
|-------------|--|--|---|
|             |  | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required  |
| R1          | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.  | First day of the first calendar quarter, after applicable regulatory approvals   | First calendar quarter after Board of Trustees adoption   |
|             | <ul style="list-style-type: none"> <li>For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability</li> </ul> | First day of the first calendar quarter 12 months after applicable regulatory approvals  | First day of the first calendar quarter 12 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For supervisory elements as described in PRC-023-2(i) - Attachment A, Section 1.6</li> </ul>  | First day of the first calendar quarter 24 months after applicable regulatory approvals  | First day of the first calendar quarter 24 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For switch-on-to-fault schemes as described in PRC-023-2(i) - Attachment A, Section 1.3</li> </ul>  | Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2(i) or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013) | Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2(i) or July 1, 2011 <sup>1</sup>            |
|             | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on |

<sup>1</sup> July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement      | Applicability   | Effective Date   |  |
|------------------|---|--|--|
|                  |   | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required   |
|                  |   | list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   | a list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   |
|                  |   |  |  |
| <b>R2 and R3</b> | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above | First day of the first calendar quarter after applicable regulatory approvals  | First day of the first calendar quarter after Board of Trustees adoption   |
|                  | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6   | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date |

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Applicability   | Effective Date   |   |
|-------------|---|--|---|
|             |   | Jurisdictions where Regulatory Approval is Required                                      | Jurisdictions where No Regulatory Approval is Required                              |
| <b>R4</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R5</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R6</b>   | Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5 | First day of the first calendar quarter 18 months after applicable regulatory approvals  | First day of the first calendar quarter 18 months after Board of Trustees adoption  |



### B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

#### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>2</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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<sup>2</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>3</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>4</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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<sup>3</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

<sup>4</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

## Standard PRC-023-2(i) — Transmission Relay Loadability

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(i) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>   |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>   |

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High   | Severe   |
|-------------|-------|--|--|--|
|             |       |  |  | The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.<br><br>OR<br><br>The Planning Coordinator used the criteria established within   |

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe   |
|-------------|-------|---|--|--|
|             |       | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p> |



**Standard PRC-023-2(i) — Transmission Relay Loadability**

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| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
|             |       |          |      | <p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available

at: [http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking  |
|---------|--|---|--|
| 1       | February 12, 2008                                  | Approved by Board of Trustees   | New  |
| 1       | March 19, 2008                                     | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata   |
| 1       | March 18, 2010                                     | Approved by FERC  |  |
| 1       | Filed for approval<br>April 19, 2010               | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision   |
| 2       | March 10, 2011<br>approved by Board<br>of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)   |
| 2       | March 15, 2012                                     | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |  |
| 2(i)    | TBD  | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023 — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Generator protection relays that are susceptible to load.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

**PRC-023 — Attachment B**

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>5</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>5</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-2(i) — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

## A. Introduction

### 1. Title: Transmission Relay Loadability

### 2. Number: PRC-023-2(i)

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

### 4. Applicability

#### 4.1. Functional Entity

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(i) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2(i) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(i) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinators

#### 4.2. Circuits

##### 4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

##### 4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

### 5. Effective Dates

The effective dates of the requirements in the PRC-023-2(i) standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Applicability  | Effective Date   |   |
|-------------|--|--|---|
|             |  | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required  |
| R1          | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.  | First day of the first calendar quarter, after applicable regulatory approvals   | First calendar quarter after Board of Trustees adoption   |
|             | <ul style="list-style-type: none"> <li>For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability</li> </ul> | First day of the first calendar quarter 12 months after applicable regulatory approvals  | First day of the first calendar quarter 12 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For supervisory elements as described in PRC-023-2(i) - Attachment A, Section 1.6</li> </ul>  | First day of the first calendar quarter 24 months after applicable regulatory approvals  | First day of the first calendar quarter 24 months after Board of Trustees adoption  |
|             | <ul style="list-style-type: none"> <li>For switch-on-to-fault schemes as described in PRC-023-2(i) - Attachment A, Section 1.3</li> </ul>  | Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2(i) or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013) | Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2(i) or July 1, 2011 <sup>1</sup>            |
|             | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a  | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on |

<sup>1</sup> July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement      | Applicability   | Effective Date   |  |
|------------------|---|--|--|
|                  |   | Jurisdictions where Regulatory Approval is Required  | Jurisdictions where No Regulatory Approval is Required   |
|                  |   | list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   | a list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date   |
|                  |   |  |  |
| <b>R2 and R3</b> | Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above | First day of the first calendar quarter after applicable regulatory approvals  | First day of the first calendar quarter after Board of Trustees adoption   |
|                  | Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6   | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date | Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(i) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date |



**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Applicability   | Effective Date   |   |
|-------------|---|--|---|
|             |   | Jurisdictions where Regulatory Approval is Required                                      | Jurisdictions where No Regulatory Approval is Required                              |
| <b>R4</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R5</b>   | Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12   | First day of the first calendar quarter six months after applicable regulatory approvals | First day of the first calendar quarter six months after Board of Trustees adoption |
| <b>R6</b>   | Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5 | First day of the first calendar quarter 18 months after applicable regulatory approvals  | First day of the first calendar quarter 18 months after Board of Trustees adoption  |

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>2</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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<sup>2</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>3</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>4</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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<sup>3</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

<sup>4</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

## Standard PRC-023-2(i) — Transmission Relay Loadability

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(i) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

## **D. Compliance**

### **1. Compliance Monitoring Process**

#### **1.1. Compliance Monitoring Responsibility**

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

#### **1.2. Data Retention**

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>   |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>   |

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High   | Severe   |
|-------------|-------|--|--|--|
|             |       |  |  | The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A  | N/A  | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.<br><br>OR<br><br>The Planning Coordinator used the criteria established within   |



**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe   |
|-------------|-------|---|--|--|
|             |       | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p> |

**Standard PRC-023-2(i) — Transmission Relay Loadability**

| Requirement | Lower | Moderate | High | Severe   |
|-------------|-------|----------|------|--|
|             |       |          |      | <p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available

at: [http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking  |
|---------|--|---|--|
| 1       | February 12, 2008                                  | Approved by Board of Trustees   | New  |
| 1       | March 19, 2008                                     | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata   |
| 1       | March 18, 2010                                     | Approved by FERC  |  |
| 1       | Filed for approval<br>April 19, 2010               | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision   |
| 2       | March 10, 2011<br>approved by Board<br>of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)   |
| 2       | March 15, 2012                                     | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |  |
| 2(i)    | TBD  | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023 — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Generator protection relays that are susceptible to load.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

## PRC-023 — Attachment B

### Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

### Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>5</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>5</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-2(i) — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

### A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-4
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
  - 4.1. **Functional Entity:**
    - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinator
  - 4.2. **Circuits:**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 **Circuits Subject to Requirement R6:**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**5. Effective Dates:** See Implementation Plan.

### B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

#### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.



7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Data Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

### **1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

### **1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-4 — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High   | Severe  |
|-------------|-------|--|--|---|
|             |       |  |  | <p>OR</p> <p>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.</p>  |
| <b>R4</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.</p> |
| <b>R5</b>   | N/A   | N/A  | N/A  | <p>The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.</p>  |
| <b>R6</b>   | N/A   | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more</p> | <p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24</p> | <p>The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>  |

**Standard PRC-023-4 — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |

**Standard PRC-023-4 — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
|             |       | <p>the list was established or updated. (part 6.2)</p> |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |



**E. Regional Differences**

None.

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available

at: [http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |

**Standard PRC-023-4 — Transmission Relay Loadability**

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| <b>Version</b> | <b>Date</b> | <b>Action</b>                         | <b>Change Tracking</b>   |
|----------------|-------------|---------------------------------------|--|
| 4              | TBD         | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

### PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

### PRC-023-4 — Attachment B

#### Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

#### Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

## Standard PRC-023-4 — Transmission Relay Loadability

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

## A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-~~43~~
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
  - 4.1. **Functional Entity:**
    - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-~~43~~ - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~43~~ - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
    - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-~~43~~ - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
    - 4.1.4 Planning Coordinator
  - 4.2. **Circuits:**
    - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
      - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
      - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
      - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
      - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
    - 4.2.2 **Circuits Subject to Requirement R6:**
      - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

### Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating<sup>1</sup> of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
  - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
  - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
  - 115% of the highest emergency rating of the series capacitor.
  - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

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<sup>1</sup> When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
  - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
  - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability<sup>2</sup>.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
  - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
  - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature<sup>3</sup>.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
  - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
  - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
  - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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<sup>2</sup> As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

<sup>3</sup> IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.



13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-43, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-43 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-43, Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

### **C. Measures**

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-~~43~~, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

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

#### 1.2. Data Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

**1.3. Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

**1.4. Additional Compliance Information**

None.

2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe  |
|-------------|-------|----------|------|---|
| <b>R1</b>   | N/A   | N/A      | N/A  | <p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p> |
| <b>R2</b>   | N/A   | N/A      | N/A  | <p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>  |
| <b>R3</b>   | N/A   | N/A      | N/A  | <p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>   |

**Standard PRC-023-43 — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High  | Severe   |
|-------------|-------|---|---|--|
|             |       |   |   | OR<br>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.  |
| <b>R4</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports. |
| <b>R5</b>   | N/A   | N/A   | N/A   | The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.  |
| <b>R6</b>   | N/A   | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more | The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 | The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.  |

**Standard PRC-023-43 — Transmission Relay Loadability**

| Requirement | Lower | Moderate  | High   | Severe  |
|-------------|-------|---|--|---|
|             |       | <p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p> | <p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p> | <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p> |

**Standard PRC-023-43 — Transmission Relay Loadability**

| Requirement | Lower | Moderate   | High | Severe  |
|-------------|-------|--|------|---|
|             |       | <p>the list was established or updated. (part 6.2)</p> |      | <p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p> |

**E. Regional Differences**

None.

**F. Supplemental Technical Reference Document**

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available

at: [http://www.nerc.com/fileUploads/File/Standards/Relay\\_Loadability\\_Reference\\_Doc\\_Clean\\_Final\\_2008July3.pdf](http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf)

**Version History**

| Version | Date   | Action  | Change Tracking   |
|---------|--|---|---|
| 1       | February 12, 2008                            | Approved by Board of Trustees   | New   |
| 1       | March 19, 2008                               | Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”                    | Errata  |
| 1       | March 18, 2010                               | Approved by FERC  |   |
| 1       | Filed for approval April 19, 2010            | Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733 | Revision  |
| 2       | March 10, 2011 approved by Board of Trustees | Revised to address initial set of directives from Order 733   | Revision (Project 2010-13)  |
| 2       | March 15, 2012                               | FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)                                |   |
| 3       | November 7, 2013                             | Adopted by NERC Board of Trustees   | Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections. |



**Standard PRC-023-~~43~~ — Transmission Relay Loadability**

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| Version       | Date | Action                                | Change Tracking  |
|---------------|------|---------------------------------------|--|
| <del>43</del> | TBD  | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**PRC-023-43 — Attachment A**

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
  - 1.1. Phase distance.
  - 1.2. Out-of-step tripping.
  - 1.3. Switch-on-to-fault.
  - 1.4. Overcurrent relays.
  - 1.5. Communications aided protection schemes including but not limited to:
    - 1.5.1 Permissive overreach transfer trip (POTT).
    - 1.5.2 Permissive under-reach transfer trip (PUTT).
    - 1.5.3 Directional comparison blocking (DCB).
    - 1.5.4 Directional comparison unblocking (DCUB).
  - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
  - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications except as noted in section 1.6.
  - 2.2. Protection systems intended for the detection of ground fault conditions.
  - 2.3. Protection systems intended for protection during stable power swings.
  - 2.4. Not used.
  - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
  - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
  - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
  - 2.8. Relay elements associated with dc lines.
  - 2.9. Relay elements associated with dc converter transformers.

PRC-023-43 — Attachment B

**Circuits to Evaluate**

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

**Criteria**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses<sup>4</sup> performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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<sup>4</sup> Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

**A. Introduction**

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-3a
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Purchasing Selling Entities.
5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

**B. Requirements**

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

**C. Measures**

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

**D. Compliance**

1. **Compliance Monitoring Process**

1.1. **Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

**1.3. Data Retention**

Not specified.

**1.4. Additional Compliance Information**

Not specified.

**Standard TOP-005-3a — Operational Reliability Information**

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**2. Violation Severity Levels:**

| <b>R#</b> | <b>Lower</b>   | <b>Moderate</b> | <b>High</b> | <b>Severe</b>  |
|-----------|--|-----------------|-------------|--|
| R1        | N/A  | N/A             | N/A         | The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.             |
| R2        | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A             | N/A         | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |
| R3        | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A             | N/A         | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |

**E. Regional Variances**

None identified.

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|------------------|---|--|
| 0              | April 1, 2005    | Effective Date  | New  |
| 0              | August 8, 2005   | Removed “Proposed” from Effective Date  | Errata   |
| 1              |                  | Removed the Reliability Coordinator from the list of responsible functional entities<br>Deleted R1 and R1.1<br>Modified M1 to omit the reference to the Reliability Coordinator<br>Deleted VSLs for R1 and R1.1 | Revised  |
| 2              | October 17, 2008 | Adopted by NERC Board of Trustees   | New  |
| 2              | March 17, 2011   | Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)   |  |
| 2a             | April 21, 2011   | Added FERC approved Interpretation  |  |
| 3a             | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



**Attachment 1-TOP-005**

**Electric System Reliability Data**

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

- 1.** The following information shall be updated at least every ten minutes:
  - 1.1.** Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
    - 1.1.1** Status.
    - 1.1.2** MW or ampere loadings.
    - 1.1.3** MVA capability.
    - 1.1.4** Transformer tap and phase angle settings.
    - 1.1.5** Key voltages.
  - 1.2.** Generator data.
    - 1.2.1** Status.
    - 1.2.2** MW and MVAR capability.
    - 1.2.3** MW and MVAR net output.
    - 1.2.4** Status of automatic voltage control facilities.
  - 1.3.** Operating reserve.
    - 1.3.1** MW reserve available within ten minutes.
  - 1.4.** Balancing Authority demand.
    - 1.4.1** Instantaneous.
  - 1.5.** Interchange.
    - 1.5.1** Instantaneous actual interchange with each Balancing Authority.
    - 1.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
    - 1.5.3** Interchange Schedules for the next 24 hours.
  - 1.6.** Area Control Error and frequency.
    - 1.6.1** Instantaneous area control error.
    - 1.6.2** Clock hour area control error.
    - 1.6.3** System frequency at one or more locations in the Balancing Authority.
- 2.** Other operating information updated as soon as available.
  - 2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
  - 2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
  - 2.3.** Forecast peak demand for current day and next day.
  - 2.4.** Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded Remedial Action Schemes.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3<sup>1</sup></b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12</b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0 Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation  |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>   |

<sup>1</sup> In the current version of the Standard (TOP-005-2a), this requirement is R2.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### **Conclusion**

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

## A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-~~32~~a
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
  - 4.1. Transmission Operators.
  - 4.2. Balancing Authorities.
  - 4.3. Purchasing Selling Entities.
5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

## B. Requirements

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

## C. Measures

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

## D. Compliance

1. **Compliance Monitoring Process**
  - 1.1. **Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

**1.2. Compliance Monitoring Period and Reset Time Frame**

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

**1.3. Data Retention**

Not specified.

**1.4. Additional Compliance Information**

Not specified.

2. Violation Severity Levels:

| R# | Lower  | Moderate | High | Severe   |
|----|--|----------|------|--|
| R1 | N/A  | N/A      | N/A  | The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.             |
| R2 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |
| R3 | The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators. | N/A      | N/A  | The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator. |

**E. Regional Variances**

None identified.

**Version History**

| Version         | Date             | Action  | Change Tracking  |
|-----------------|------------------|---|--|
| 0               | April 1, 2005    | Effective Date  | New  |
| 0               | August 8, 2005   | Removed “Proposed” from Effective Date  | Errata   |
| 1               |                  | Removed the Reliability Coordinator from the list of responsible functional entities<br>Deleted R1 and R1.1<br>Modified M1 to omit the reference to the Reliability Coordinator<br>Deleted VSLs for R1 and R1.1 | Revised  |
| 2               | October 17, 2008 | Adopted by NERC Board of Trustees   | New  |
| 2               | March 17, 2011   | Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)   |  |
| 2a              | April 21, 2011   | Added FERC approved Interpretation  |  |
| <del>32</del> a | TBD              | Adopted by the NERC Board of Trustees   | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |



**Attachment 1-TOP-005**

**Electric System Reliability Data**

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

- 1.** The following information shall be updated at least every ten minutes:
  - 1.1.** Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
    - 1.1.1** Status.
    - 1.1.2** MW or ampere loadings.
    - 1.1.3** MVA capability.
    - 1.1.4** Transformer tap and phase angle settings.
    - 1.1.5** Key voltages.
  - 1.2.** Generator data.
    - 1.2.1** Status.
    - 1.2.2** MW and MVAR capability.
    - 1.2.3** MW and MVAR net output.
    - 1.2.4** Status of automatic voltage control facilities.
  - 1.3.** Operating reserve.
    - 1.3.1** MW reserve available within ten minutes.
  - 1.4.** Balancing Authority demand.
    - 1.4.1** Instantaneous.
  - 1.5.** Interchange.
    - 1.5.1** Instantaneous actual interchange with each Balancing Authority.
    - 1.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
    - 1.5.3** Interchange Schedules for the next 24 hours.
  - 1.6.** Area Control Error and frequency.
    - 1.6.1** Instantaneous area control error.
    - 1.6.2** Clock hour area control error.
    - 1.6.3** System frequency at one or more locations in the Balancing Authority.
- 2.** Other operating information updated as soon as available.
  - 2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
  - 2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
  - 2.3.** Forecast peak demand for current day and next day.
  - 2.4.** Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded Remedial Action Schemes.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>TOP-005-1 Requirement R3<sup>1</sup></b></p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p><b>IRO-005-1 Requirement R12</b></p> <p><b>R12.</b> Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p><b>PRC-012-0 Requirements R1 and R1.3</b></p> <p><b>R1.</b> Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;"><b>R1.3.</b> Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p> |
| Background Information for Interpretation  |
| <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>   |

<sup>1</sup> In the current version of the Standard (TOP-005-2a), this requirement is R2.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

### Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

**A. Introduction**

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(i)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** May 13, 2009

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.3.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.4.** Have established normal (pre-contingency) operating procedures in place.
    - R1.3.5.** Have all projected firm transfers modeled.



Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|------------------|---|--|
| 0              | April 1, 2005    | Effective Date  | New  |
| 0              | February 8, 2005 | BOT Approval  | Revised  |
| 0              | June 3, 2005     | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata   |
| 0              | July 24, 2007    | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata   |
| 0.1            | October 29, 2008 | BOT adopted errata changes; updated version number to "0.1"       | Errata   |
| 0.1            | May 13, 2009     | FERC Approved – Updated Effective Date                            | Revised  |
| 0.1(i)         | TBD              | Adopted by the NERC Board of Trustees                             | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-001-0.1(i) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |



**Standard TPL-001-0.1(i) — System Performance Under Normal Conditions**

|  |   |                |                |                         |                |  |
|--|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|  | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit  | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(i)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** May 13, 2009

## B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
    - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
    - R1.3.5. Have all projected firm transfers modeled.

- R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
  - R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
  - R1.3.8.** Include existing and planned facilities.
  - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(i)\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(i)\_R1 and TPL-001-0.1(i)\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(i)\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### **1.2. Compliance Monitoring Period and Reset Time Frame**

Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>      | <b>Action</b>   | <b>Change Tracking</b>   |
|----------------|------------------|---|--|
| 0              | April 1, 2005    | Effective Date  | New  |
| 0              | February 8, 2005 | BOT Approval  | Revised  |
| 0              | June 3, 2005     | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2   | Errata   |
| 0              | July 24, 2007    | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata   |
| 0.1            | October 29, 2008 | BOT adopted errata changes; updated version number to "0.1"       | Errata   |
| 0.1            | May 13, 2009     | FERC Approved – Updated Effective Date                            | Revised  |
| 0.1(i)         | TBD              | Adopted by the NERC Board of Trustees                             | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-001-0.1(i) — System Performance Under Normal Conditions**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   |  | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault   | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

**Standard TPL-001-0.1(i) — System Performance Under Normal Conditions**

|  |   |                |                |                         |                |  |
|--|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|  | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit  | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**A. Introduction**

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0(i)b
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities.

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.
    - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

## **Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

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- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0(i)b\_R1 and TPL-002-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0(i)b\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

**Compliance Monitor:** Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.



**Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| <b>Version</b> | <b>Date</b>        | <b>Action</b>  | <b>Change Tracking</b>   |
|----------------|--------------------|--|--|
| 0              | February 8, 2005   | Adopted by NERC Board of Trustees  | New  |
| 0              | April 1, 2005      | Effective Date   | New  |
| 0a             | July 30, 2008      | Adopted by NERC Board of Trustees  | New  |
| 0a             | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0b             | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation   |
| 0b             | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation   |
| 0(i)b          | TBD                | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

**Table I. Transmission System Standards — Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

## Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element

|   |   |                |                |                         |                |  |
|---|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <p>5. Breaker (failure or internal Fault)</p> <hr style="border-top: 1px dashed black;"/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**Appendix 1**

**Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

**TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
  - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**Requirement R1.3.2**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2  
Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Appendix 2**

| <b>Requirement Number and Text of Requirement</b>  |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| <b>Background Information for Interpretation</b>   |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> <li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li> <li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li> <li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li> </ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> </ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>4. Single Pole (dc) Line</li> </ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| <b>Conclusion</b>  |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

## **Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

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More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.



**A. Introduction**

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0(i)b
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities.

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
  - R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.
    - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

## **Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0(i)b\_R1 and TPL-002-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0(i)b\_R3.

### **D. Compliance**

#### **1. Compliance Monitoring Process**

##### **1.1. Compliance Monitoring Responsibility**

**Compliance Monitor:** Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element**

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

**E. Regional Differences**

1. None identified.

**Version History**

| Version | Date               | Action   | Change Tracking  |
|---------|--------------------|--|--|
| 0       | February 8, 2005   | Adopted by NERC Board of Trustees  | New  |
| 0       | April 1, 2005      | Effective Date   | New  |
| 0a      | July 30, 2008      | Adopted by NERC Board of Trustees  | New  |
| 0a      | October 23, 2008   | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0b      | November 5, 2009   | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009   | Interpretation   |
| 0b      | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)  | Interpretation   |
| 0(i)b   | TBD                | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Table I. Transmission System Standards — Normal and Emergency Conditions

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

## Standard TPL-002-0(i)b — System Performance Following Loss of a Single BES Element

|   |   |                |                |                         |                |  |
|---|---|----------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>   | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> | 1. Generator   | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|   | 1. Generator  | 3. Transformer |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |                |                |                         |                |  |
| <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <p>5. Breaker (failure or internal Fault)</p> <hr style="border-top: 1px dashed black;"/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> |   |                |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Appendix 1

### Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### Requirement R1.3.2

#### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2  
Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12  
Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.



## Appendix 2

| Requirement Number and Text of Requirement   |
|--|
| <p><b>R1.3.</b> Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following <b>Category B of Table 1</b> (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p><b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>  |
| Background Information for Interpretation  |
| <p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> <li>1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”</li> <li>2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”</li> <li>3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”</li> </ol> <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> </ol> <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>4. Single Pole (dc) Line</li> </ol> <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p> |
| Conclusion   |
| <p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>   |

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

**A. Introduction**

- 1. Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- 2. Number:** TPL-003-0(i)b
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** April 23, 2010

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
- R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.

## **Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

- R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
- R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0(i)b\_R1 and TPL-003-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0(i)b\_R3.

### **D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

Compliance Monitor: Regional Reliability Organizations.

### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

2.1. **Level 1:** Not applicable.

2.2. **Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

1. None identified.

## Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 0       | February 8, 2005 | Adopted by NERC Board of Trustees  | New  |
| 0       | April 1, 2005    | Effective Date   | New  |
| 0       | April 1, 2005    | Add parenthesis to item “e” on page 8.   | Errata   |
| 0a      | July 30, 2008    | Adopted by NERC Board of Trustees  |  |
| 0a      | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0a      | April 23, 2010   | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation   |
| 0b      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees   |  |
| 0b      | June 20, 2013    | FERC order issued approving Interpretation   |  |
| 0(i)b   | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category  | Contingencies  | System Limits or Impacts  |  |                                |
|---|--|---|--|--------------------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No           |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
| SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                             |

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

|   |  |              |                |                         |                |  |
|---|--|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <hr/> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer   |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section   |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## **Appendix 1**

### **Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO**

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
  - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### **Requirement R1.3.2**

#### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:**

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*



## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(i) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

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<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

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### Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

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<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

**A. Introduction**

- 1. Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- 2. Number:** TPL-003-0(i)b
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
- 4. Applicability:**
  - 4.1.** Planning Authority
  - 4.2.** Transmission Planner
- 5. Effective Date:** April 23, 2010

**B. Requirements**

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
- R1.1.** Be made annually.
  - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
  - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1.** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
    - R1.3.5.** Have all projected firm transfers modeled.



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- R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
- R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0(i)b\_R1, the Planning Authority and Transmission Planner shall each:
  - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
    - R2.1.1.** Including a schedule for implementation.
    - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
    - R2.1.3.** Consider lead times necessary to implement plans.
  - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### **C. Measures**

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0(i)b\_R1 and TPL-003-0(i)b\_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0(i)b\_R3.

### **D. Compliance**

- 1. Compliance Monitoring Process**
  - 1.1. Compliance Monitoring Responsibility**

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Compliance Monitor: Regional Reliability Organizations.

### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

### 1.3. Data Retention

None specified.

### 1.4. Additional Compliance Information

None.

## 2. Levels of Non-Compliance

2.1. **Level 1:** Not applicable.

2.2. **Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

1. None identified.

## Version History

| Version | Date             | Action   | Change Tracking  |
|---------|------------------|--|--|
| 0       | February 8, 2005 | Adopted by NERC Board of Trustees  | New  |
| 0       | April 1, 2005    | Effective Date   | New  |
| 0       | April 1, 2005    | Add parenthesis to item “e” on page 8.   | Errata   |
| 0a      | July 30, 2008    | Adopted by NERC Board of Trustees  |  |
| 0a      | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised  |
| 0a      | April 23, 2010   | FERC approval of interpretation of TPL-003-0 R1.3.12   | Interpretation   |
| 0b      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees   |  |
| 0b      | June 20, 2013    | FERC order issued approving Interpretation   |  |
| 0(i)b   | TBD              | Adopted by the NERC Board of Trustees  | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Table I. Transmission System Standards – Normal and Emergency Conditions

| Category   | Contingencies  | System Limits or Impacts  |   |                                |
|--|--|---|---|--------------------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers  | Cascading <sup>c</sup> Outages |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No  | No                             |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>  | No<br>No<br>No<br>No           |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>   | No                             |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section<br>2. Breaker (failure or internal Fault)   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No                       |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>   | No                             |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No                       |
|  | SLG Fault, with Delayed Clearing <sup>c</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No           |

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

|   |   |              |                |                         |                |  |
|---|---|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <hr/> <p>5. Breaker (failure or internal Fault)</p> <hr/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer  |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section  |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

## Appendix 1

### Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

#### **TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

#### **TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

### Requirement R1.3.2

#### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

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### **Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:**

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

### **The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0\_R1 [or TPL-003-0\_R1] and TPL-002-0\_R2 [or TPL-003-0\_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

**Requirement R1.3.12**

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:**

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:**

*MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

**Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements**

**Appendix 2**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning



## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(i) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

## Standard TPL-003-0(i)b — System Performance Following Loss of Two or More BES Elements

### Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

### A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0(i)a
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** April 1, 2005

### B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.
    - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
    - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
    - R1.3.8. Include the effects of existing and planned control devices.

## Standard TPL-004-0(i)a — System Performance Following Extreme BES Events

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**R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

**R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### C. Measures

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0(i)a\_R1.

**M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0(i)a\_R1.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

##### 1.3. Data Retention

None specified.

##### 1.4. Additional Compliance Information

None.

#### 2. Levels of Non-Compliance

**2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Not applicable.

### E. Regional Differences

1. None identified.

### Version History

| Version | Date             | Action   | Change Tracking |
|---------|------------------|--|-----------------|
| 0       | April 1, 2005    | Effective Date                                   | New             |
| 0a      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees |                 |

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|       |               |                                       |  |
|-------|---------------|---------------------------------------|--|
| 0a    | June 20, 2013 | Interpretation approved in FERC order |  |
| 0(i)a | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

**Standard TPL-004-0(i)a — System Performance Following Extreme BES Events**

**Table I. Transmission System Standards – Normal and Emergency Conditions**

| Category   | Contingencies  | System Limits or Impacts  |   |                      |
|--|--|---|---|----------------------|
|  | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers  | Cascading Outages    |
| <b>A</b><br>No Contingencies   | All Facilities in Service  | Yes   | No  | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                   | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup>  | No<br>No<br>No<br>No |
|  | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>   | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section<br>2. Breaker (failure or internal Fault)   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No             |
|  | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>   | No                   |
|  | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :<br>5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup>  | No<br>No             |
|  | SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section   | Yes<br>Yes<br>Yes<br>Yes  | Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup><br>Planned/<br>Controlled <sup>c</sup> | No<br>No<br>No<br>No |



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|   |  |              |                |                         |                |  |
|---|--|--------------|----------------|-------------------------|----------------|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <hr/> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | 1. Generator | 3. Transformer | 2. Transmission Circuit | 4. Bus Section | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
| 1. Generator  | 3. Transformer   |              |                |                         |                |  |
| 2. Transmission Circuit   | 4. Bus Section   |              |                |                         |                |  |

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

**Appendix 1**

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

### Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

### Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

**A. Introduction**

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0(i)a
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
  - 4.1. Planning Authority
  - 4.2. Transmission Planner
5. **Effective Date:** April 1, 2005

**B. Requirements**

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
  - R1.1. Be made annually.
  - R1.2. Be conducted for near-term (years one through five).
  - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
    - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
    - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
    - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
    - R1.3.4. Have all projected firm transfers modeled.
    - R1.3.5. Include existing and planned facilities.
    - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
    - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
    - R1.3.8. Include the effects of existing and planned control devices.

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**R1.3.9.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Consider all contingencies applicable to Category D.

**R2.** The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

### C. Measures

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0(i)a\_R1.

**M2.** The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0(i)a\_R1.

### D. Compliance

#### 1. Compliance Monitoring Process

##### 1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

##### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

##### 1.3. Data Retention

None specified.

##### 1.4. Additional Compliance Information

None.

#### 2. Levels of Non-Compliance

**2.1. Level 1:** A valid assessment, as defined above, for the near-term planning horizon is not available.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** Not applicable.

### E. Regional Differences

1. None identified.

### Version History

| Version | Date             | Action   | Change Tracking |
|---------|------------------|--|-----------------|
| 0       | April 1, 2005    | Effective Date                                   | New             |
| 0a      | February 7, 2013 | Interpretation adopted by NERC Board of Trustees |                 |



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|       |               |                                       |  |
|-------|---------------|---------------------------------------|--|
| 0a    | June 20, 2013 | Interpretation approved in FERC order |  |
| 0(i)a | TBD           | Adopted by the NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |

Table I. Transmission System Standards – Normal and Emergency Conditions

| Category  | Contingencies  | System Limits or Impacts  |  |                      |
|---|--|---|--|----------------------|
|   | Initiating Event(s) and Contingency Element(s)   | System Stable and both Thermal and Voltage Limits within Applicable Rating <sup>a</sup> | Loss of Demand or Curtailed Firm Transfers                               | Cascading Outages    |
| <b>A</b><br>No Contingencies  | All Facilities in Service  | Yes   | No   | No                   |
| <b>B</b><br>Event resulting in the loss of a single element.                                | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault.  | Yes<br>Yes<br>Yes<br>Yes  | No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup><br>No <sup>b</sup> | No<br>No<br>No<br>No |
|   | Single Pole Block, Normal Clearing <sup>c</sup> :<br>4. Single Pole (dc) Line  | Yes   | No <sup>b</sup>  | No                   |
| <b>C</b><br>Event(s) resulting in the loss of two or more (multiple) elements.              | SLG Fault, with Normal Clearing <sup>c</sup> :<br>1. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 2. Breaker (failure or internal Fault)   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing <sup>c</sup> :<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | Bipolar Block, with Normal Clearing <sup>c</sup> :<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing <sup>c</sup> :   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 5. Any two circuits of a multiple circuit towerline <sup>f</sup>   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
| SLG Fault, with Delayed Clearing <sup>e</sup> (stuck breaker or protection system failure): | 6. Generator   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 7. Transformer   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 8. Transmission Circuit  | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |
|   | 9. Bus Section   | Yes   | Planned/<br>Controlled <sup>c</sup>                                      | No                   |

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|   |   |  |
|---|---|--|
| <p><b>D<sup>d</sup></b></p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p> | <p>3Ø Fault, with Delayed Clearing<sup>e</sup> (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> <li>1. Generator</li> <li>2. Transmission Circuit</li> <li>3. Transformer</li> <li>4. Bus Section</li> </ol> <hr/> <p>3Ø Fault, with Normal Clearing<sup>e</sup>:</p> <ol style="list-style-type: none"> <li>5. Breaker (failure or internal Fault)</li> <li>6. Loss of towerline with three or more circuits</li> <li>7. All transmission lines on a common right-of way</li> <li>8. Loss of a substation (one voltage level plus transformers)</li> <li>9. Loss of a switching station (one voltage level plus transformers)</li> <li>10. Loss of all generating units at a station</li> <li>11. Loss of a large Load or major Load center</li> <li>12. Failure of a fully redundant Remedial Action Scheme to operate when required</li> <li>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</li> <li>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</li> </ol> | <p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> <li>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.</li> <li>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.</li> <li>▪ Evaluation of these events may require joint studies with neighboring systems.</li> </ul> |
|---|---|--|

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

**Date submitted:** December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

| Standard   | Requirement (and text)   |
|------------|--|
| TPL-003-0a | <b>R1.3.1</b> Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.  |
| TPL-003-0a | <b>R1.3.10.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.   |
| TPL-003-0a | <b>R1.5.</b> Consider all contingencies applicable to Category C.  |
| TPL-004-0  | <b>R1.3.1.</b> Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. |
| TPL-004-0  | <b>R1.3.7.</b> Include the effects of existing and planned protection systems, including any backup or redundant systems.  |
| TPL-004-0  | <b>R1.4.</b> Consider all contingencies applicable to Category D.  |

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)<sup>1</sup> (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

**Question 1:** For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>2</sup> of either "stuck breaker" or "protection system failure" contingency<sup>3</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1<sup>4</sup> requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

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<sup>1</sup> NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

<sup>2</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>3</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>4</sup> "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

**Question 2:** For the phrase “Delayed Clearing<sup>5</sup>” used in Category C<sup>6</sup> contingencies 6-9 and Category D<sup>7</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>8</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

### Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects<sup>9</sup> of either “stuck breaker” or “protection system failure” contingency<sup>10</sup>, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

### Response 1

<sup>5</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>6</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>7</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>8</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

<sup>9</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

<sup>10</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 $\phi$ ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

## Question 2

For the phrase “Delayed Clearing<sup>11</sup>” used in Category C<sup>12</sup> contingencies 6-9 and Category D<sup>13</sup> contingencies 1-4, to what extent does the description in Table 1, footnote (e)<sup>14</sup> require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

## Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

<sup>11</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

<sup>12</sup> As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

<sup>13</sup> As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

<sup>14</sup> Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

## Standard TPL-004-0(i)a — System Performance Following Extreme BES Events

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The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.



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# “Remedial Action Scheme” Definition Development Background and Frequently Asked Questions

Project 2010-05.2 – Special Protection Systems

October 2014

**RELIABILITY | ACCOUNTABILITY**



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## Introduction

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The Project 2010-05.2 – Special Protection Systems Standard Drafting Team (SDT) developed this background and Frequently Asked Questions (FAQ) document to explain the key concepts incorporated into the revised definition, as well as the team’s approach and intent. This document will remain available as part of the official project record for the Remedial Action Scheme (RAS) definition. The drafting team has updated this (FAQ) document to reflect all revisions made to the RAS definition based on stakeholder feedback.

Contact the Standards Developer, Al McMeekin, at 404-446-9675 or at [al.mcmeekin@nerc.net](mailto:al.mcmeekin@nerc.net) with any comments or questions.

# Background and FAQ – RAS Definition Development

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## Existing Glossary of Terms Used in NERC Reliability Standards Definitions

The existing Glossary of Terms Used in NERC Reliability Standards defines **SPS** or **RAS** as: “An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.”

The Glossary of Terms Used in NERC Reliability Standards defines a **Protection System** as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

## Revision of the Glossary of Terms Used in NERC Reliability Standards Definition

### Purpose of Revision of the Glossary of Terms Used in NERC Reliability Standards SPS or RAS

The existing Glossary of Terms Used in NERC Reliability Standards definition for an SPS/RAS lacks the clarity and specificity necessary to consistently identify what equipment or schemes qualify as an SPS/RAS across the eight NERC Regions. This confusion leads to inconsistent application of the SPS/RAS-related NERC Reliability Standards.

The existing definition also lacks clarity in the actions stipulated as characteristics of an SPS/RAS. The actions listed in the definition are so broad that the definition may unintentionally include schemes whose purpose is not expressly related to preserving system reliability in response to predetermined system conditions. Inclusion of any scheme taking “corrective action other than isolation of faulted components to maintain system reliability” could be interpreted to mean that devices such as voltage regulators and switching controls for shunt capacitors should be included. This inclusion would then make these devices subject to requirements such as those addressing single-component failure considerations (sometimes referred to as redundancy considerations) in the SPS/RAS-related NERC Reliability Standards.

### Recommendation to Change the Term to RAS Only

Currently, both terms, SPS and RAS, are used in the eight NERC Regions. The SDT contends that a single term promotes consistency. The SDT therefore recommends that the term RAS be retained as the industry-recognized term and that the term SPS ultimately be retired. The term RAS is more descriptive of the purpose for which the scheme is installed.

The term RAS also eliminates the confusion associated with the two defined terms, “Special Protection System” and “Protection System.” The inclusion of Protection System in the term Special Protection System implies that SPS are a subset of Protection Systems.

### Effects of Using Only the Term RAS in the Existing NERC Reliability Standards

The existing NERC Reliability Standards and Glossary of Terms Used in NERC Reliability Standards use the terms, SPS and RAS interchangeably. In most cases, both terms are included in the standards and written as: “SPS or RAS.” The SDT evaluated the existing standards and recommended any necessary revisions to retain the single term “RAS”. Many of the same changes would be required regardless of which single term is retained. A summary of the occurrences of the terms is included in the posted document *Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards*.

## Proposed Definition of RAS

**Remedial Action Scheme:** A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic reclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Exclusion List Explanations

**a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes the isolation of faulted components because that is a protective function. Protection Systems installed for the purpose of detecting Faults on non-BES Elements are not RAS, and are not subject to NERC Reliability Standards. The SDT accepts this exclusion consistent with industry practice.

**b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes UFLS and UVLS because they are protective functions that have unique design and implementation considerations that are covered by NERC Reliability Standards PRC-006-1 and PRC-010-1. This exclusion emphasizes “distributed” UVLS relays to highlight that the exclusion covers UVLS Programs. The SDT accepts this exclusion consistent with industry practice.

Centrally controlled undervoltage-based load shedding is a RAS.

**c. Out-of-step tripping and power swing blocking**

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes out-of-step relaying because it is a protective function. The SDT maintained the exclusion but changed the wording from “out-of-step relaying” to “out-of-step tripping and power swing blocking” to reflect current industry terminology.

**d. Automatic reclosing schemes**

Automatic reclosing schemes, whether single-pole or three-pole, are used to minimize system impacts and restoration efforts by System Operators. Automatic reclosing, in itself, is not a RAS; however, if integrated into a larger scheme that performs additional corrective actions to accomplish the objective(s) listed in the RAS definition, then it would be part of a RAS. For example, a scheme that rejects or runs back generation to avoid instability or thermal overloads in addition to initiating automatic reclosing would constitute a RAS. The drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) automatic reclosing schemes. Automatic reclosing schemes that restore load to an alternate source would typically not be a RAS; however, system reconfiguration which transfers the load to another source for purposes other than load restoration typically would be a RAS.

**e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service**

Schemes applied on a single Element to protect it from damage from non-Fault conditions are protective functions and are not RAS. Other examples of schemes that would qualify within this exclusion are reverse power, volts/hertz, winding temperature, and loss of cooling. The SDT accepts this exclusion consistent with industry practice.

- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated**

Controllers that switch or regulate these devices are not RAS. The SDT accepts this exclusion consistent with industry practice. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations.

- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device**

The purpose of such controllers is to switch shunt devices to restore an acceptable operating range of a single FACTS device. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations. The SDT accepts this exclusion consistent with industry practice.

- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched**

Schemes or controllers that assist a System Operator in coordinating the switching of shunt reactors and shunt capacitors that would otherwise be manually switched are not remedial in the sense of being mitigations in response to predetermined System conditions, but are for general application to all System conditions, e.g. optimizing voltage profiles or minimizing losses. The SDT accepts this exclusion consistent with industry practice.

- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open**

When one end of a line is open, unacceptable voltage levels can occur. Opening the remote terminal(s) to de-energize the transmission line removes this voltage rise. Alternatively, restoration conditions may require energization or synchronizing at a specific terminal. These schemes have not historically been regarded as RAS, and the SDT accepts this exclusion consistent with industry practice.

- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)**

These schemes are designed to protect load in an electrical island that might otherwise operate at an off-nominal frequency or voltage, or facilitate restoration. Actions taken on islanded facilities will not impact the interconnected BES because the facilities are isolated. The SDT accepts this exclusion consistent with industry practice.

- k. Automatic sequences that proceed when manually initiated solely by a System Operator**

Automated sequences created to simplify the actions of a System Operator are not RAS because the decision to activate a specific sequence is left to the System Operator. If the automated sequence fails to execute correctly, the System Operator has the option to manually set those actions in motion. The SDT accepts this exclusion consistent with industry practice.

The arming of a RAS by a System Operator is not the same as manual initiation of an automatic sequence. Arming enables the scheme but the RAS must still detect the critical conditions it was designed to mitigate and then take action.

**l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations**

Modulation of HVdc and FACTS via supplementary controls is occasionally used for damping local or inter-area oscillations. It is similar in function to a Power System Stabilizer (PSS), which is a component of excitation controls in a generating unit. PSS are also not classified as RAS. The SDT accepts these HVdc and FACTS exclusions consistent with industry practice.

**m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities; (e.g., currents or torsional oscillations)**

Historically, SSR protection schemes that directly detect sub-synchronous quantities and the related mitigation are not RAS. The SDT accepts this exclusion consistent with industry practice.

However, SSR protection schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

**n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing**

These traditional generator and turbine controls are not RAS. The SDT accepts this exclusion consistent with industry practice.



## Explanations Regarding Changes from the Exclusion List Cited in the SAMS-SPCS Report

The SDT revised the straw man definition proposed in the SAMS-SPCS report; however, the proposed definition is consistent with the SAMS-SPCS intent. As a result of the revisions, it is no longer necessary to explicitly state the following exclusions.

### 1. Schemes that prevent high line voltage by automatically switching the affected line

These schemes are now addressed by exclusion (e) (protection from overvoltage) and exclusion (i) (automatic de-energization of a line when one end is open) in the proposed definition.

### 2. Protection schemes that operate local breakers other than those on the faulted circuit to facilitate Fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a Fault or to reduce fault duty

These schemes are now addressed by exclusion (a) in the proposed definition.

### 3. Blanket exclusion for SSR protection schemes

The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

### 4. A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

These schemes are now addressed by exclusion (a) in the proposed definition.

## Frequently Asked Questions

### What is the relationship between a Remedial Action Scheme and a Protection System?

The existing definition of a Protection System in the Glossary of Terms Used in NERC Reliability Standards is a component-based definition that was developed in conjunction with NERC Reliability Standard PRC-005-2 Protection System Maintenance. The definition lists components such as “protective relays which respond to electrical quantities” that represent the building blocks of a Protection System. All protective schemes include some combination of these building blocks but not necessarily all of them, for example, many protective schemes do not have the “communications systems...” component. In other cases, protective schemes like RAS may have all of the Protection System components as well as other pieces of equipment such as programmable logic controllers.

### Why does the proposed definition have an exclusion list?

The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS.

### Why did the SDT not propose a screening process to identify RAS?

The SDT contends that a comprehensive definition with specific exclusions is the best way to achieve consistency and immediacy in RAS identification. The SDT asserts that a study-based screening process would be labor-intensive and dependent on assumptions that could vary among the entities performing the studies.

**Why does the proposed definition not include the classification types suggested in the SPCS-SAMS report?**

The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.

**Why did the SDT not specifically reference the Transmission Planning (TPL) standards in the proposed definition?**

The SDT acknowledges that many RAS are installed to address the performance requirements of the TPL standards; however, they are also installed to address other reliability concerns.

**Would automatic actions taken by an Energy Management System (EMS), Supervisory Control and Data Acquisition (SCADA), or Distribution Control System (DCS) be considered a RAS?**

The above-mentioned control systems support and enable grid operations by issuing control commands mostly to geographically distributed power System devices. In this normal application, e.g. automatic generation control (AGC), these systems are not considered to be RAS. However, if these systems are configured to detect predetermined conditions and take corrective actions consistent with the RAS definition, these automatic functions (not the entire EMS) would be considered to be part of a RAS. The identification of RAS is not dependent upon the specific hardware or platform utilized in the scheme. For example, an automatic UVLS scheme centrally controlled through an EMS would be a RAS.

**Would controllers at the terminals of a High Voltage direct current (HVdc) Facility be considered a RAS?**

HVdc terminal controls such as those which maintain proper converter operation, regulate current, voltage or power flow, or that provide protection for the HVdc Facility itself do not meet the definition of RAS. However, an HVdc control scheme designed to take corrective actions based on predetermined System conditions, such as backing down power transfer on an HVdc Facility following a Contingency to avoid overload of another BES Element *would be* part of a RAS.

**Why are local cross-trip schemes RAS?**

Switching in the same substation (including transfer- or cross-trip schemes) to trip Elements other than the protected Element is a System reconfiguration and is therefore a RAS. Reconfiguring the System can be a critical factor in reliability and merits the review and oversight associated with RAS.

**What are the Implementation Plan time frames?**

The effective date of the RAS definition as noted in the Implementation Plan is the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. The drafting team notes that RAS owners could use this time to evaluate their existing schemes for determining whether they are RAS, based on the new definition.

The Implementation Plan also provides owners of newly identified RAS twenty-four (24) calendar months beyond the effective date of the definition (i.e., at least 36 months after approval by a governmental authority) to be fully compliant with the existing standards applicable to the revised definition of Remedial Action Scheme. The drafting team contends that this time frame provide entities sufficient time to transition schemes to RAS and become compliant with the revised standards outlined in the Implementation Plan.

Note: These timeframes are not applicable to new RAS implemented subsequent to the effective date of the new definition. New RAS must comply with all applicable standards as they are implemented.

## **Coordination with Project 2008-02 – Undervoltage Load Shedding**

As part of the development of PRC-010-1, the Project 2008-02 UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1:

**Undervoltage Load Shedding Program (UVLS Program):** An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

Note that the definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintained that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, centrally controlled undervoltage-based load shedding should be subject to RAS-related Reliability Standards.

The Project 2010-05.2 SPS SDT agreed with the Project 2008-02 UVLS SDT that the design and characteristics of centrally controlled undervoltage-based load shedding are more appropriately categorized as RAS. The SPS SDT revised the definition of RAS to clarify that the definition is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. The SDT coordinated this change with the Project 2008-02 UVLS SDT. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as a RAS. As a result, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective date of the revised definition of RAS.

## Attachment A – SDT Members

| Project 2010-05.2 – Special Protection Systems SDT |                                   |                                       |
|--|-----------------------------------|---------------------------------------|
|  | Participant                       | Entity                                |
| Chair  | Gene Henneberg                    | NV Energy / Berkshire Hathaway Energy |
| Vice Chair   | Bobby Jones                       | Southern Company                      |
| Member   | Amos Ang                          | Southern California Edison            |
|  | John Ciufu                        | Hydro One Inc.                        |
|  | Alan Engelmann                    | ComEd / Exelon                        |
|  | Davis Erwin                       | Pacific Gas and Electric              |
|  | Sharma Kolluri                    | Entergy                               |
|  | Charles-Eric Langlois             | Hydro-Quebec TransEnergie             |
|  | Robert J. O'Keefe                 | American Electric Power               |
|  | Hari Singh                        | Xcel Energy                           |
| NERC Staff   | Al McMeekin (Standards Developer) | NERC                                  |
|  | Lacey Ourso (Standards Developer) | NERC                                  |
|  | Phil Tatro (Technical Advisor)    | NERC                                  |
|  | Bill Edwards (Legal Counsel)      | NERC                                  |

**NERC**

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# “Remedial Action Scheme” Definition Development Background and Frequently Asked Questions

Project 2010-05.2 – Special Protection Systems

~~August~~October 2014

**RELIABILITY | ACCOUNTABILITY**



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## Introduction

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The Project 2010-05.2 – Special Protection Systems Standard Drafting Team (SDT) developed this background and Frequently Asked Questions (FAQ) document to explain the key concepts incorporated into the revised definition, as well as the team’s approach and intent. This document will remain available as part of the official project record for the Remedial Action Scheme (RAS) definition. ~~In addition to providing individual responses to commenters for the first formal comment period conducted June-July, 2014, t~~The drafting team has updated this ~~Frequently Asked Questions~~ (FAQ) document to reflect all revisions made to the RAS definition based on stakeholder feedback.

Contact the Standards Developer, Al McMeekin, at 404-446-9675 or at [al.mcmeekin@nerc.net](mailto:al.mcmeekin@nerc.net) with any comments or questions.

## Background and FAQ – RAS Definition Development

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### Existing Glossary of Terms Used in NERC Reliability Standards Definitions

The existing Glossary of Terms Used in NERC Reliability Standards defines **SPS** or **RAS** as: “An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.”

The Glossary of Terms Used in NERC Reliability Standards defines a **Protection System** as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

### Revision of the Glossary of Terms Used in NERC Reliability Standards Definition

#### Purpose of Revision of the Glossary of Terms Used in NERC Reliability Standards SPS or RAS

The existing Glossary of Terms Used in NERC Reliability Standards definition for an SPS/RAS lacks the clarity and specificity necessary to consistently identify what equipment or schemes qualify as an SPS/RAS across the eight NERC Regions. This confusion leads to inconsistent application of the SPS/RAS-related NERC Reliability Standards.

The existing definition also lacks clarity in the actions stipulated as characteristics of an SPS/RAS. The actions listed in the definition are so broad that the definition may unintentionally include schemes whose purpose is not expressly related to preserving system reliability in response to predetermined system conditions. Inclusion of any scheme taking “corrective action other than isolation of faulted components to maintain system reliability” could be interpreted to mean that devices such as voltage regulators and switching controls for shunt capacitors should be included. This inclusion would then make these devices subject to requirements such as those addressing single-component failure considerations (sometimes referred to as redundancy considerations) in the SPS/RAS-related NERC Reliability Standards.

#### Recommendation to Change the Term to RAS Only

Currently, both terms, SPS and RAS, are used in the eight NERC Regions. The SDT contends that a single term promotes consistency. The SDT therefore recommends that the term RAS be retained as the industry-recognized term and that the term SPS ultimately be retired. The term RAS is more descriptive of the purpose for which the scheme is installed.

The term RAS also eliminates the confusion associated with the two defined terms, “Special Protection System” and “Protection System.” The inclusion of Protection System in the term Special Protection System implies that SPS are a subset of Protection Systems.



### Effects of Using Only the Term RAS in the Existing NERC Reliability Standards

The existing NERC Reliability Standards and Glossary of Terms Used in NERC Reliability Standards use the terms, SPS and RAS interchangeably. In most cases, both terms are included in the standards and written as: “SPS or RAS.” The SDT evaluated the existing standards and recommended any necessary revisions to retain the single term “RAS”. Many of the same changes would be required regardless of which single term is retained. A summary of the occurrences of the terms is included in the posted document *Uses of “Special Protection System” and “Remedial Action Scheme” in Reliability Standards*.

## Proposed Definition of RAS

**Remedial Action Scheme:** A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

- a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
- b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
- c. Out-of-step tripping and power swing blocking
- d. Automatic R<sub>r</sub>eclosing schemes
- e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
- k. Automatic sequences that proceed when manually initiated solely by a System Operator
- l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

- m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
- n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

## Exclusion List Explanations

### a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes the isolation of faulted components because that is a protective function. [Protection Systems installed for the purpose of detecting Faults on non-BES Elements are not RAS, and are not subject to NERC Reliability Standards.](#) The SDT accepts this exclusion consistent with industry practice.

### b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes UFLS and UVLS because they are protective functions that have unique design and implementation considerations that are covered by NERC Reliability Standards PRC-006-1 and PRC-010-1. This exclusion emphasizes “distributed” UVLS relays to highlight that the exclusion covers UVLS Programs. The SDT accepts this exclusion consistent with industry practice.

Centrally controlled undervoltage-based load shedding is a RAS.

### c. Out-of-step tripping and power swing blocking

The existing Glossary of Terms Used in NERC Reliability Standards definition of SPS/RAS excludes out-of-step relaying because it is a protective function. The SDT maintained the exclusion but changed the wording from “out-of-step relaying” to “out-of-step tripping and power swing blocking” to reflect current industry terminology.

### d. Automatic ~~R~~eclosing schemes

Automatic reclosing schemes, whether single-pole or three-pole, are used to minimize system impacts and restoration efforts by System Operators. Automatic reclosing, in itself, is not a RAS; however, if integrated into a larger scheme that performs additional corrective actions to accomplish the objective(s) listed in the RAS definition, then it would be part of a RAS. For example, a scheme that rejects or runs back generation to avoid instability or thermal overloads in addition to initiating automatic reclosing would constitute a RAS. The drafting team contends that auto-sectionalizing for restoration following a Fault would typically fall under exclusion (d) [Automatic-automatic Rreclosing schemes;](#) [Automatic reclosing schemes that restore load to an alternate source would typically not be a RAS;](#) however, system reconfiguration which transfers the load to another source [for purposes other than load restoration](#) typically would be a RAS.

### e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

Schemes applied on a single Element to protect it from damage from non-Fault conditions are protective functions and are not RAS. [Other examples of schemes that would qualify within this exclusion are reverse power, volts/hertz, winding temperature, and loss of cooling.](#) The SDT accepts this exclusion consistent with industry practice.

- f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated**

Controllers that switch or regulate these devices are not RAS. The SDT accepts this exclusion consistent with industry practice. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations.

- g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device**

The purpose of such controllers is to switch shunt devices to restore an acceptable operating range of a single FACTS device. Exclusions (f) and (g) are complementary in that (f) provides a broad exception for local controls at the same station while (g) provides a specific exclusion for FACTS control of shunt devices at one or more other stations. The SDT accepts this exclusion consistent with industry practice.

- h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched**

Schemes or controllers that assist a System Operator in coordinating the switching of shunt reactors and shunt capacitors that would otherwise be manually switched are not remedial in the sense of being mitigations in response to predetermined System conditions, but are for general application to all System conditions, e.g. optimizing voltage profiles or minimizing losses. The SDT accepts this exclusion consistent with industry practice.

- i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open**

When one end of a line is open, unacceptable voltage levels can occur. Opening the remote terminal(s) to de-energize the transmission line removes this voltage rise. Alternatively, restoration conditions may require energization or synchronizing at a specific terminal. These schemes have not historically been regarded as RAS, and the SDT accepts this exclusion consistent with industry practice.

- j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)**

These schemes are designed to protect load in an electrical island that might otherwise operate at an off-nominal frequency or voltage, or facilitate restoration. Actions taken on islanded facilities will not impact the interconnected BES because the facilities are isolated. The SDT accepts this exclusion consistent with industry practice.

- k. Automatic sequences that proceed when manually initiated solely by a System Operator**

Automated sequences created to simplify the actions of a System Operator are not RAS because the decision to activate a specific sequence is left to the System Operator. If the automated sequence fails to execute correctly, the System Operator has the option to manually set those actions in motion. The SDT accepts this exclusion consistent with industry practice.

The arming of a RAS by a System Operator is not the same as manual initiation of an automatic sequence. Arming enables the scheme but the RAS must still detect the critical conditions it was designed to mitigate and then take action.

**l. Modulation of HVdc or FACTS via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations**

Modulation of HVdc and FACTS via supplementary controls is occasionally used for damping local or inter-area oscillations. It is similar in function to a Power System Stabilizer (PSS), which is a component of excitation controls in a generating unit. PSS are also not classified as RAS. The SDT accepts these HVdc and FACTS exclusions consistent with industry practice.

**m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities; (e.g., currents or torsional oscillations)**

Historically, SSR protection schemes that directly detect sub-synchronous quantities and the related mitigation are not RAS. The SDT accepts this exclusion consistent with industry practice.

However, SSR protection schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

**n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing**

These traditional generator and turbine controls are not RAS. The SDT accepts this exclusion consistent with industry practice.

## Explanations Regarding Changes from the Exclusion List Cited in the SAMS-SPCS Report

The SDT revised the straw man definition proposed in the SAMS-SPCS report; however, the proposed definition is consistent with the SAMS-SPCS intent. As a result of the revisions, it is no longer necessary to explicitly state the following exclusions.

### 1. Schemes that prevent high line voltage by automatically switching the affected line

These schemes are now addressed by exclusion (e) (protection from overvoltage) and exclusion (i) (automatic de-energization of a line when one end is open) in the proposed definition.

### 2. Protection schemes that operate local breakers other than those on the faulted circuit to facilitate Fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a Fault or to reduce fault duty

These schemes are now addressed by exclusion (a) in the proposed definition.

### 3. Blanket exclusion for SSR protection schemes

The proposed definition excludes schemes that directly detect sub-synchronous quantities; however, SSR mitigation schemes installed to detect distinct System configurations and loading conditions (that studies have shown may make a generator vulnerable to SSR), and take action to trip the generator or bypass the series capacitor, are classified as RAS.

### 4. A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

These schemes are now addressed by exclusion (a) in the proposed definition.

## Frequently Asked Questions

### What is the relationship between a Remedial Action Scheme and a Protection System?

The existing ~~NERC Glossary of Terms~~ definition of a Protection System [in the Glossary of Terms Used in NERC Reliability Standards](#) is a component-based definition that was developed in conjunction with NERC Reliability Standard PRC-005-2 Protection System Maintenance. The definition lists components such as “protective relays which respond to electrical quantities” that represent the building blocks of a Protection System. All protective schemes include some combination of these building blocks but not necessarily all of them, for example, many protective schemes do not have the “communications systems...” component. In other cases, protective schemes like RAS may have all of the Protection System components as well as other pieces of equipment such as programmable logic controllers.

### Why does the proposed definition have an exclusion list?

The definition must be broad enough to include the variety of System conditions monitored and corrective actions taken by RAS. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list also assures that commonly applied protection and control systems are not unintentionally included as RAS.

### Why did the SDT not propose a screening process to identify RAS?

The SDT contends that a comprehensive definition with specific exclusions is the best way to achieve consistency and immediacy in RAS identification. The SDT asserts that a study-based screening process would be labor-intensive and dependent on assumptions that could vary among the entities performing the studies.

**Why does the proposed definition not include the classification types suggested in the SPCS-SAMS report?**

The classification of a RAS is not necessary for defining whether or not a scheme qualifies as a RAS. Informal feedback from many stakeholders indicated uncertainty about the classification types. Therefore, the SDT decided not to include RAS classification types within the definition. The classifications are more appropriately addressed concurrently with revisions to the RAS-related Reliability Standards.

**Why did the SDT not specifically reference the Transmission Planning (TPL) standards in the proposed definition?**

The SDT acknowledges that many RAS are installed to address the performance requirements of the TPL standards; however, they are also installed to address other reliability concerns.

**Would automatic actions taken by an Energy Management System (EMS), Supervisory Control and Data Acquisition (SCADA), or Distribution Control System (DCS) be considered a RAS?**

The above-mentioned control systems support and enable grid operations by issuing control commands mostly to geographically distributed power System devices. In this normal application, e.g. automatic generation control (AGC), these systems are not considered to be RAS. However, if these systems are configured to detect predetermined conditions and take corrective actions consistent with the RAS definition, these automatic functions (not the entire EMS) would be considered to be part of a RAS. The identification of RAS is not dependent upon the specific hardware or platform utilized in the scheme. For example, an automatic UVLS scheme centrally controlled through an EMS would be a RAS.

**Would controllers at the terminals of a High Voltage direct current (HVdc) Facility be considered a RAS?**

HVdc terminal controls such as those which maintain proper converter operation, regulate current, voltage or power flow, or that provide protection for the HVdc Facility itself do not meet the definition of RAS. However, an HVdc control scheme designed to take corrective actions based on predetermined System conditions, such as backing down power transfer on an HVdc Facility following a Contingency to avoid overload of another BES Element would be part of a RAS.

**Why are local cross-trip schemes RAS?**

Switching in the same substation (including transfer- or cross-trip schemes) to trip Elements other than the protected Element is a System reconfiguration and is therefore a RAS. Reconfiguring the System can be a critical factor in reliability and merits the review and oversight associated with RAS.

**What are the Implementation Plan time frames?**

The effective date of the RAS definition as noted in the Implementation Plan is the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction. The drafting team notes that RAS owners could use this time to evaluate their existing schemes for determining whether they are RAS, based on the new definition.

The Implementation Plan also provides owners of newly identified RAS twenty-four (24) calendar months beyond the effective date of the definition (i.e., at least 36 months after approval by a governmental authority) to be fully compliant with the existing standards applicable to the revised definition of Remedial Action Scheme. The drafting team contends that this time frame provide entities sufficient time to transition schemes to RAS and become compliant with the revised standards outlined in the Implementation Plan.

Note: These timeframes are not applicable to new RAS implemented subsequent to the effective date of the new definition. New RAS must comply with all applicable standards as they are implemented.

## Coordination with Project 2008-02 – Undervoltage Load Shedding

As part of the development of PRC-010-1, the Project 2008-02 UVLS SDT ~~is introducing~~ a new ~~NERC Glossary~~ term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1:

**Undervoltage Load Shedding Program (UVLS Program):** An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading ~~impacting the Bulk Electric System (BES)~~. Centrally controlled undervoltage-based load shedding is not included.

Note that the definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT ~~maintains~~ maintained that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, centrally controlled undervoltage-based load shedding should be subject to RAS-related Reliability Standards.

The Project 2010-05.2 SPS SDT ~~agrees~~ agreed with the Project 2008-02 UVLS SDT that the design and characteristics of centrally controlled undervoltage-based load shedding are more appropriately categorized as RAS. The SPS SDT revised the definition of RAS to clarify that the definition is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. The SDT ~~is coordinating~~ this change with the Project 2008-02 UVLS SDT. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as a RAS. As a result, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective date of the revised definition of RAS.

## Attachment A – SDT Members

| Project 2010-05.2 – Special Protection Systems SDT |  |                                       |
|--|--|---------------------------------------|
|  | Participant  | Entity                                |
| Chair  | Gene Henneberg   | NV Energy / Berkshire Hathaway Energy |
| Vice Chair   | Bobby Jones  | Southern Company                      |
| Member   | Amos Ang   | Southern California Edison            |
|  | John Ciufu   | Hydro One Inc.                        |
|  | Alan Engelmann   | ComEd / Exelon                        |
|  | Davis Erwin  | Pacific Gas and Electric              |
|  | Sharma Kolluri   | Entergy                               |
|  | Charles-Eric Langlois                                    | Hydro-Quebec TransEnergie             |
|  | Robert J. O'Keefe  | American Electric Power               |
|  | Hari Singh   | Xcel Energy                           |
| NERC Staff   | Al McMeekin (Standards Developer)                        | NERC                                  |
|  | <a href="#"><u>Lacey Ourso (Standards Developer)</u></a> | <a href="#"><u>NERC</u></a>           |
|  | Phil Tatro (Technical Advisor)                           | NERC                                  |
|  | Bill Edwards (Legal Counsel)                             | NERC                                  |



# Standards Announcement

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Remedial Action Scheme

**Final Ballot Now Open through November 6, 2014**

### [Now Available](#)

A final ballot for the **Revised Definition of Remedial Action Scheme** is open through **8 p.m. Eastern, Thursday, November 6, 2014.**

Background information for this project can be found on the [project page](#).

### **Instructions for Balloting**

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the definition by clicking [here](#).

### **Next Steps**

The voting results for the definition will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact [Al McMeekin](#),  
Standards Developer, or at 404-446-2560.*

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# Standards Announcement

## Project 2010-05.2 Phase 2 of Protection Systems Revised Definition of Remedial Action Scheme

### Final Ballot Results

#### [Now Available](#)

A final ballot for the **Revised Definition of Remedial Action Scheme** concluded at **8 p.m. Eastern, Thursday, November 6, 2014.**

The revised definition achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results for the ballot.

| Ballot           |
|------------------|
| Quorum /Approval |
| 85.41% / 73.33%  |

Background information for this project can be found on the [project page](#).

### Next Steps

The definition and standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the [Standard Processes Manual](#).

*For more information or assistance, please contact Standards Developer, [Al McMeekin](#), or by telephone at 404-446-9675.*

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Atlanta, GA 30326  
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| Ballot Results                |   |
|-------------------------------|---|
| <b>Ballot Name:</b>           | Definition_of_Remedial_Action_Scheme_Final_Ballot_October_2014                        |
| <b>Ballot Period:</b>         | 10/28/2014 - 11/6/2014  |
| <b>Ballot Type:</b>           | Final   |
| <b>Total # Votes:</b>         | 316   |
| <b>Total Ballot Pool:</b>     | 370   |
| <b>Quorum:</b>                | <b>85.41 % The Quorum has been reached</b>  |
| <b>Weighted Segment Vote:</b> | 73.33 %   |
| <b>Ballot Results:</b>        | <b>A quorum was reached and there were sufficient affirmative votes for approval.</b> |

| Summary of Ballot Results |             |                |             |          |          |          |                                 |         |         |  |
|---------------------------|-------------|----------------|-------------|----------|----------|----------|---------------------------------|---------|---------|--|
| Segment                   | Ballot Pool | Segment Weight | Affirmative |          | Negative |          | Negative Vote without a Comment | Abstain | No Vote |  |
|                           |             |                | # Votes     | Fraction | # Votes  | Fraction |                                 |         |         |  |
| 1 - Segment 1             | 101         | 1              | 57          | 0.713    | 23       | 0.288    | 0                               | 5       | 16      |  |
| 2 - Segment 2             | 9           | 0.8            | 5           | 0.5      | 3        | 0.3      | 0                               | 1       | 0       |  |
| 3 - Segment 3             | 84          | 1              | 49          | 0.731    | 18       | 0.269    | 0                               | 7       | 10      |  |
| 4 - Segment 4             | 27          | 1              | 16          | 0.727    | 6        | 0.273    | 0                               | 0       | 5       |  |
| 5 - Segment 5             | 79          | 1              | 44          | 0.746    | 15       | 0.254    | 0                               | 9       | 11      |  |
| 6 - Segment 6             | 53          | 1              | 29          | 0.763    | 9        | 0.237    | 0                               | 6       | 9       |  |
| 7 - Segment 7             | 3           | 0.1            | 1           | 0.1      | 0        | 0        | 0                               | 0       | 2       |  |
| 8 - Segment 8             | 4           | 0.3            | 2           | 0.2      | 1        | 0.1      | 0                               | 0       | 1       |  |
| 9 - Segment 9             | 3           | 0.3            | 2           | 0.2      | 1        | 0.1      | 0                               | 0       | 0       |  |

|                 |            |            |            |             |           |              |          |           |           |
|-----------------|------------|------------|------------|-------------|-----------|--------------|----------|-----------|-----------|
| 10 - Segment 10 | 7          | 0.7        | 6          | 0.6         | 1         | 0.1          | 0        | 0         | 0         |
| <b>Totals</b>   | <b>370</b> | <b>7.2</b> | <b>211</b> | <b>5.28</b> | <b>77</b> | <b>1.921</b> | <b>0</b> | <b>28</b> | <b>54</b> |

| Individual Ballot Pool Results |  |                              |             |                               |
|--------------------------------|--|------------------------------|-------------|-------------------------------|
| Segment                        | Organization                                     | Member                       | Ballot      | NERC Notes                    |
| 1                              | Ameren Services                                  | Eric Scott                   | Affirmative |                               |
| 1                              | American Electric Power                          | Paul B Johnson               | Affirmative |                               |
| 1                              | American Transmission Company, LLC               | Andrew Z Puszta              | Affirmative |                               |
| 1                              | Arizona Public Service Co.                       | Brian Cole                   | Affirmative |                               |
| 1                              | Associated Electric Cooperative, Inc.            | John Bussman                 | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1                              | Austin Energy                                    | James Armke                  | Affirmative |                               |
| 1                              | Avista Utilities                                 | Heather Rosentrater          | Affirmative |                               |
| 1                              | Balancing Authority of Northern California       | Kevin Smith                  | Affirmative |                               |
| 1                              | Baltimore Gas & Electric Company                 | Christopher J Scanlon        | Affirmative |                               |
| 1                              | Basin Electric Power Cooperative                 | David Rudolph                |             |                               |
| 1                              | BC Hydro and Power Authority                     | Patricia Robertson           | Affirmative |                               |
| 1                              | Black Hills Corp                                 | Wes Wingen                   |             |                               |
| 1                              | Bonneville Power Administration                  | Donald S. Watkins            | Affirmative |                               |
| 1                              | Bryan Texas Utilities                            | John C Fontenot              | Affirmative |                               |
| 1                              | CenterPoint Energy Houston Electric, LLC         | John Brockhan                | Affirmative |                               |
| 1                              | Central Electric Power Cooperative               | Michael B Bax                | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1                              | Central Iowa Power Cooperative                   | Kevin J Lyons                | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1                              | City of Tallahassee                              | Daniel S Langston            | Affirmative |                               |
| 1                              | Clark Public Utilities                           | Jack Stamper                 | Affirmative |                               |
| 1                              | Colorado Springs Utilities                       | Shawna Speer                 | Negative    |                               |
| 1                              | Consolidated Edison Co. of New York              | Christopher L de Graffenried | Affirmative |                               |
| 1                              | Dairyland Power Coop.                            | Robert W. Roddy              | Affirmative |                               |
| 1                              | Dayton Power & Light Co.                         | Hertzel Shamash              | Affirmative |                               |
| 1                              | Deseret Power                                    | James Tucker                 |             |                               |
| 1                              | Dominion Virginia Power                          | Larry Nash                   | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1                              | Duke Energy Carolina                             | Doug E Hils                  | Affirmative |                               |
| 1                              | Entergy Transmission                             | Oliver A Burke               | Affirmative |                               |
| 1                              | FirstEnergy Corp.                                | William J Smith              | Affirmative |                               |
| 1                              | Florida Keys Electric Cooperative Assoc.         | Dennis Minton                | Affirmative |                               |
| 1                              | Florida Power & Light Co.                        | Mike O'Neil                  | Affirmative |                               |
| 1                              | Gainesville Regional Utilities                   | Richard Bachmeier            |             |                               |
| 1                              | Georgia Transmission Corporation                 | Jason Snodgrass              | Affirmative |                               |
| 1                              | Great River Energy                               | Gordon Pietsch               | Affirmative |                               |
| 1                              | Hydro One Networks, Inc.                         | Muhammed Ali                 | Affirmative |                               |
| 1                              | Hydro-Quebec TransEnergie                        | Martin Boisvert              | Affirmative |                               |
| 1                              | Idaho Power Company                              | Molly Devine                 | Affirmative |                               |
| 1                              | International Transmission Company Holdings Corp | Michael Moltane              | Negative    |                               |
| 1                              | JDRJC Associates                                 | Jim D Cyrulewski             | Abstain     |                               |
| 1                              | JEA  | Ted E Hobson                 | Affirmative |                               |
| 1                              | KAMO Electric Cooperative                        | Walter Kenyon                | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1                              | Kansas City Power & Light Co.                    | Daniel Gibson                | Affirmative |                               |
| 1                              | Lakeland Electric                                | Larry E Watt                 |             |                               |
| 1                              | Lincoln Electric System                          | Doug Bantam                  |             |                               |
| 1                              | Long Island Power Authority                      | Robert Ganley                | Affirmative |                               |

|   |  |                         |             |                               |
|---|--|-------------------------|-------------|-------------------------------|
| 1 | Lower Colorado River Authority                   | Martyn Turner           | Affirmative |                               |
| 1 | M & A Electric Power Cooperative                 | William Price           | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1 | Manitoba Hydro                                   | Jo-Anne M Ross          | Affirmative |                               |
| 1 | MEAG Power                                       | Danny Dees              | Affirmative |                               |
| 1 | MidAmerican Energy Co.                           | Terry Harbour           | Negative    |                               |
| 1 | Minnkota Power Coop. Inc.                        | Daniel L Inman          | Affirmative |                               |
| 1 | Muscatine Power & Water                          | Andrew J Kurriger       | Abstain     |                               |
| 1 | N.W. Electric Power Cooperative, Inc.            | Mark Ramsey             | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1 | National Grid USA                                | Michael Jones           | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1 | NB Power Corporation                             | Alan MacNaughton        |             |                               |
| 1 | Nebraska Public Power District                   | Jamison Cawley          | Negative    |                               |
| 1 | New York Power Authority                         | Bruce Metruck           | Affirmative |                               |
| 1 | Northeast Missouri Electric Power Cooperative    | Kevin White             | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1 | Northeast Utilities                              | William Temple          | Affirmative |                               |
| 1 | Northern Indiana Public Service Co.              | Julaine Dyke            | Abstain     |                               |
| 1 | Ohio Valley Electric Corp.                       | Scott R Cunningham      | Affirmative |                               |
| 1 | Oklahoma Gas and Electric Co.                    | Terri Pyle              | Affirmative |                               |
| 1 | Omaha Public Power District                      | Doug Peterchuck         | Affirmative |                               |
| 1 | Oncor Electric Delivery                          | Jen Fiegel              | Affirmative |                               |
| 1 | Orlando Utilities Commission                     | Brad Chase              |             |                               |
| 1 | Otter Tail Power Company                         | Daryl Hanson            |             |                               |
| 1 | Pacific Gas and Electric Company                 | Bangalore Vijayraghavan |             |                               |
| 1 | Peak Reliability                                 | Jared Shakespeare       | Affirmative |                               |
| 1 | Platte River Power Authority                     | John C. Collins         | Affirmative |                               |
| 1 | Portland General Electric Co.                    | John T Walker           |             |                               |
| 1 | Potomac Electric Power Co.                       | David Thorne            | Affirmative |                               |
| 1 | PPL Electric Utilities Corp.                     | Brenda L Truhe          | Abstain     |                               |
| 1 | Public Service Company of New Mexico             | Laurie Williams         | Affirmative |                               |
| 1 | Public Service Electric and Gas Co.              | Kenneth D. Brown        | Affirmative |                               |
| 1 | Public Utility District No. 1 of Okanogan County | Dale Dunckel            |             |                               |
| 1 | Puget Sound Energy, Inc.                         | Denise M Lietz          | Affirmative |                               |
| 1 | Rochester Gas and Electric Corp.                 | John C. Allen           | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1 | Sacramento Municipal Utility District            | Tim Kelley              | Affirmative |                               |
| 1 | Salt River Project                               | Robert Kondziolka       | Affirmative |                               |
| 1 | San Diego Gas & Electric                         | Will Speer              |             |                               |
| 1 | SaskPower  | Wayne Guttormson        | Abstain     |                               |
| 1 | Seattle City Light                               | Pawel Krupa             | Affirmative |                               |
| 1 | Seminole Electric Cooperative, Inc.              | Glenn Spurlock          | Negative    |                               |
| 1 | Sho-Me Power Electric Cooperative                | Denise Stevens          | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1 | Snohomish County PUD No. 1                       | Long T Duong            | Affirmative |                               |
| 1 | South Carolina Electric & Gas Co.                | Tom Hanzlik             | Affirmative |                               |
| 1 | South Carolina Public Service Authority          | Shawn T Abrams          | Negative    |                               |
| 1 | Southern California Edison Company               | Steven Mavis            | Affirmative |                               |
| 1 | Southern Company Services, Inc.                  | Robert A. Schaffeld     | Affirmative |                               |
| 1 | Southern Illinois Power Coop.                    | William Hutchison       | Affirmative |                               |
| 1 | Southwest Transmission Cooperative, Inc.         | John Shaver             | Negative    |                               |
| 1 | Sunflower Electric Power Corporation             | Noman Lee Williams      | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 1 | Tacoma Power                                     | John Merrell            | Negative    | COMMENT RECEIVED              |

|   |   |                               |             |                               |
|---|---|-------------------------------|-------------|-------------------------------|
| 1 | Tennessee Valley Authority                            | Howell D Scott                | Negative    | COMMENT RECEIVED              |
| 1 | Tri-State Generation & Transmission Association, Inc. | Tracy Sliman                  | Negative    |                               |
| 1 | Tucson Electric Power Co.                             | John Tolo                     | Affirmative |                               |
| 1 | U.S. Bureau of Reclamation                            | Richard T Jackson             |             |                               |
| 1 | United Illuminating Co.                               | Jonathan Appelbaum            | Affirmative |                               |
| 1 | Westar Energy   | Allen Klassen                 |             |                               |
| 1 | Western Area Power Administration                     | Lloyd A Linke                 | Negative    | COMMENT RECEIVED              |
| 1 | Wolverine Power Supply Coop., Inc.                    | Michelle Clements             |             |                               |
| 1 | Xcel Energy, Inc.                                     | Gregory L Pieper              | Affirmative |                               |
| 2 | BC Hydro  | Venkataramakrishnan Vinnakota | Negative    | NO COMMENT RECEIVED           |
| 2 | California ISO  | Rich Vine                     | Affirmative |                               |
| 2 | Electric Reliability Council of Texas, Inc.           | Cheryl Moseley                | Affirmative |                               |
| 2 | Independent Electricity System Operator               | Leonard Kula                  | Affirmative |                               |
| 2 | ISO New England, Inc.                                 | Matthew F Goldberg            | Negative    |                               |
| 2 | MISO  | Marie Knox                    | Abstain     |                               |
| 2 | New York Independent System Operator                  | Gregory Campoli               | Negative    |                               |
| 2 | PJM Interconnection, L.L.C.                           | stephanie campzon             | Affirmative |                               |
| 2 | Southwest Power Pool, Inc.                            | Charles H. Yeung              | Affirmative |                               |
| 3 | AEP   | Michael E Deloach             | Affirmative |                               |
| 3 | Alabama Power Company                                 | Robert S Moore                | Affirmative |                               |
| 3 | Ameren Corp.  | David J Jendras               | Affirmative |                               |
| 3 | APS   | Sarah Kist                    | Affirmative |                               |
| 3 | Associated Electric Cooperative, Inc.                 | Todd Bennett                  | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 3 | Atlantic City Electric Company                        | NICOLE BUCKMAN                | Affirmative |                               |
| 3 | Avista Corp.  | Scott J Kinney                | Affirmative |                               |
| 3 | BC Hydro and Power Authority                          | Pat G. Harrington             | Affirmative |                               |
| 3 | Bonneville Power Administration                       | Rebecca Berdahl               | Affirmative |                               |
| 3 | Central Electric Power Cooperative                    | Adam M Weber                  | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 3 | Central Lincoln PUD                                   | Steve Alexanderson            | Affirmative |                               |
| 3 | City of Austin dba Austin Energy                      | Andrew Gallo                  | Affirmative |                               |
| 3 | City of Clewiston                                     | Lynne Mila                    | Affirmative |                               |
| 3 | City of Farmington                                    | Linda R Jacobson              | Abstain     |                               |
| 3 | City of Garland                                       | Ronnie C Hoeinghaus           | Abstain     |                               |
| 3 | City of Green Cove Springs                            | Mark Schultz                  | Affirmative |                               |
| 3 | City of Redding                                       | Bill Hughes                   | Affirmative |                               |
| 3 | City of Tallahassee                                   | Bill R Fowler                 | Affirmative |                               |
| 3 | City of Vineland                                      | Kathy Caignon                 |             |                               |
| 3 | Cleco Corporation                                     | Michelle A Corley             | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 3 | Colorado Springs Utilities                            | Jean Mueller                  | Negative    |                               |
| 3 | ComEd   | John Bee                      | Affirmative |                               |
| 3 | Consolidated Edison Co. of New York                   | Peter T Yost                  | Affirmative |                               |
| 3 | Consumers Energy Company                              | Gerald G Farringer            | Affirmative |                               |
| 3 | Cowlitz County PUD                                    | Russell A Noble               | Affirmative |                               |
| 3 | CPS Energy  | Jose Escamilla                | Affirmative |                               |
| 3 | Delmarva Power & Light Co.                            | Michael R. Mayer              | Affirmative |                               |
| 3 | Dominion Resources, Inc.                              | Connie B Lowe                 | Negative    |                               |
| 3 | DTE Electric  | Kent Kujala                   | Negative    |                               |
| 3 | FirstEnergy Corp.                                     | Cindy E Stewart               | Affirmative |                               |
| 3 | Florida Keys Electric Cooperative                     | Tom B Anthony                 | Affirmative |                               |
| 3 | Florida Municipal Power Agency                        | Joe McKinney                  | Affirmative |                               |
| 3 | Florida Power Corporation                             | Lee Schuster                  | Affirmative |                               |
| 3 | Gainesville Regional Utilities                        | Kenneth Simmons               | Affirmative |                               |
| 3 | Great River Energy                                    | Brian Glover                  |             |                               |
| 3 | Hydro One Networks, Inc.                              | Ayesha Sabouba                | Affirmative |                               |
| 3 | Imperial Irrigation District                          | Jesus S. Alcaraz              |             |                               |
| 3 | JEA   | Garry Baker                   |             |                               |

|   |   |                     |             |  |
|---|---|---------------------|-------------|--|
| 3 | KAMO Electric Cooperative                             | Theodore J Hilmes   | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 3 | Kansas City Power & Light Co.                         | Joshua D Bach       | Affirmative |  |
| 3 | Kissimmee Utility Authority                           | Gregory D Woessner  |             |  |
| 3 | Lakeland Electric                                     | Mace D Hunter       | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 3 | Lincoln Electric System                               | Jason Fortik        | Abstain     |  |
| 3 | Los Angeles Department of Water & Power               | Mike Anctil         | Affirmative |  |
| 3 | Louisville Gas and Electric Co.                       | Charles A. Freibert | Abstain     |  |
| 3 | M & A Electric Power Cooperative                      | Stephen D Pogue     | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 3 | Manitoba Hydro  | Greg C. Parent      | Affirmative |  |
| 3 | MEAG Power  | Roger Brand         | Affirmative |  |
| 3 | MidAmerican Energy Co.                                | Thomas C. Mielnik   | Negative    |  |
| 3 | Modesto Irrigation District                           | Jack W Savage       | Affirmative |  |
| 3 | National Grid USA                                     | Brian E Shanahan    | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 3 | Nebraska Public Power District                        | Tony Eddleman       | Negative    |  |
| 3 | New York Power Authority                              | David R Rivera      | Affirmative |  |
| 3 | Northeast Missouri Electric Power Cooperative         | Skyler Wiegmann     |             |  |
| 3 | Northern Indiana Public Service Co.                   | Ramon J Barany      | Abstain     |  |
| 3 | NW Electric Power Cooperative, Inc.                   | David McDowell      |             |  |
| 3 | Ocala Utility Services                                | Randy Hahn          | Affirmative |  |
| 3 | Oklahoma Gas and Electric Co.                         | Donald Hargrove     | Affirmative |  |
| 3 | Omaha Public Power District                           | Blaine R. Dinwiddie | Affirmative |  |
| 3 | Orlando Utilities Commission                          | Ballard K Mutters   | Affirmative |  |
| 3 | Owensboro Municipal Utilities                         | Thomas T Lyons      | Abstain     |  |
| 3 | Pacific Gas and Electric Company                      | John H Hagen        | Affirmative |  |
| 3 | Platte River Power Authority                          | Terry L Baker       | Affirmative |  |
| 3 | PNM Resources   | Michael Mertz       |             |  |
| 3 | Portland General Electric Co.                         | Thomas G Ward       | Abstain     |  |
| 3 | Potomac Electric Power Co.                            | Mark Yerger         | Affirmative |  |
| 3 | Public Service Electric and Gas Co.                   | Jeffrey Mueller     | Affirmative |  |
| 3 | Puget Sound Energy, Inc.                              | Mariah R Kennedy    | Affirmative |  |
| 3 | Sacramento Municipal Utility District                 | James Leigh-Kendall | Affirmative |  |
| 3 | Salt River Project                                    | John T. Underhill   | Affirmative |  |
| 3 | Santee Cooper   | James M Poston      | Negative    |  |
| 3 | Seattle City Light                                    | Dana Wheelock       | Affirmative |  |
| 3 | Seminole Electric Cooperative, Inc.                   | James R Frauen      | Negative    |  |
| 3 | Sho-Me Power Electric Cooperative                     | Jeff L Neas         |             |  |
| 3 | Snohomish County PUD No. 1                            | Mark Oens           | Affirmative |  |
| 3 | South Carolina Electric & Gas Co.                     | Hubert C Young      | Affirmative |  |
| 3 | Southern California Edison Company                    | Lujuanna Medina     | Affirmative |  |
| 3 | Tacoma Power  | Marc Donaldson      | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 3 | Tampa Electric Co.                                    | Ronald L. Donahey   |             |  |
| 3 | Tennessee Valley Authority                            | Ian S Grant         | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 3 | Tri-State Generation & Transmission Association, Inc. | Janelle Marriott    | Negative    |  |
| 3 | Westar Energy   | Bo Jones            | Affirmative |  |
| 3 | Wisconsin Electric Power Marketing                    | James R Keller      | Negative    |  |
| 3 | Xcel Energy, Inc.                                     | Michael Ibold       | Affirmative |  |
| 4 | Alliant Energy Corp. Services, Inc.                   | Kenneth Goldsmith   | Affirmative |  |
| 4 | Blue Ridge Power Agency                               | Duane S Dahlquist   | Negative    |  |
| 4 | Central Lincoln PUD                                   | Shamus J Gamache    |             |  |
| 4 | City of Austin dba Austin Energy                      | Reza Ebrahimian     | Affirmative |  |
| 4 | City of Redding                                       | Nicholas Zettel     | Affirmative |  |
| 4 | City Utilities of Springfield, Missouri               | John Allen          | Affirmative |  |

|   |   |                     |             |                               |
|---|---|---------------------|-------------|-------------------------------|
| 4 | Constellation Energy Control & Dispatch, L.L.C.                   | Margaret Powell     |             |                               |
| 4 | Consumers Energy Company  | Tracy Goble         | Affirmative |                               |
| 4 | Cowlitz County PUD  | Rick Syring         | Affirmative |                               |
| 4 | DTE Electric  | Daniel Herring      | Negative    |                               |
| 4 | Florida Municipal Power Agency                                    | Carol Chinn         | Affirmative |                               |
| 4 | Georgia System Operations Corporation                             | Guy Andrews         | Affirmative |                               |
| 4 | Herb Schrayshuen  | Herb Schrayshuen    | Affirmative |                               |
| 4 | Illinois Municipal Electric Agency                                | Bob C. Thomas       | Affirmative |                               |
| 4 | Indiana Municipal Power Agency                                    | Jack Alvey          |             |                               |
| 4 | Integrus Energy Group, Inc.                                       | Christopher Plante  |             |                               |
| 4 | Madison Gas and Electric Co.                                      | Joseph DePoorter    | Affirmative |                               |
| 4 | Modesto Irrigation District                                       | Spencer Tacke       | Affirmative |                               |
| 4 | Ohio Edison Company   | Douglas Hohlbaugh   | Affirmative |                               |
| 4 | Public Utility District No. 1 of Snohomish County                 | John D Martinsen    | Affirmative |                               |
| 4 | Sacramento Municipal Utility District                             | Mike Ramirez        | Affirmative |                               |
| 4 | Seattle City Light  | Hao Li              | Affirmative |                               |
| 4 | Seminole Electric Cooperative, Inc.                               | Steven R Wallace    | Negative    |                               |
| 4 | South Mississippi Electric Power Association                      | Steve McElhanev     |             |                               |
| 4 | Tacoma Public Utilities   | Keith Morisette     | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 4 | Utility Services, Inc.  | Brian Evans-Mongeon | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 4 | Wisconsin Energy Corp.  | Anthony P Jankowski | Negative    |                               |
| 5 | Amerenue  | Sam Dwyer           | Affirmative |                               |
| 5 | American Electric Power   | Thomas Foltz        | Affirmative |                               |
| 5 | Arizona Public Service Co.  | Scott Takinen       | Affirmative |                               |
| 5 | Associated Electric Cooperative, Inc.                             | Matthew Pacobit     | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 5 | BC Hydro and Power Authority                                      | Clement Ma          | Affirmative |                               |
| 5 | Boise-Kuna Irrigation District/dba Lucky peak power plant project | Mike D Kukla        | Affirmative |                               |
| 5 | Bonneville Power Administration                                   | Francis J. Halpin   | Affirmative |                               |
| 5 | Brazos Electric Power Cooperative, Inc.                           | Shari Heino         | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 5 | Calpine Corporation   | Hamid Zakery        | Negative    |                               |
| 5 | City of Austin dba Austin Energy                                  | Jeanie Doty         | Affirmative |                               |
| 5 | City of Redding   | Paul A. Cummings    | Affirmative |                               |
| 5 | City of Tallahassee   | Karen Webb          | Negative    |                               |
| 5 | Cleco Power   | Stephanie Huffman   | Negative    | SUPPORTS THIRD PARTY COMMENTS |
| 5 | Colorado Springs Utilities  | Kaleb Brimhall      | Negative    |                               |
| 5 | Con Edison Company of New York                                    | Brian O'Boyle       | Affirmative |                               |
| 5 | Consumers Energy Company  | David C Greyerbiehl | Affirmative |                               |
| 5 | Cowlitz County PUD  | Bob Essex           | Affirmative |                               |
| 5 | Dairyland Power Coop.   | Tommy Drea          | Affirmative |                               |
| 5 | Dominion Resources, Inc.  | Mike Garton         | Negative    |                               |
| 5 | DTE Electric  | Mark Stefaniak      | Negative    |                               |
| 5 | Duke Energy   | Dale Q Goodwine     | Affirmative |                               |
| 5 | Dynegy Inc.   | Dan Roethemeyer     | Affirmative |                               |
| 5 | E.ON Climate & Renewables North America, LLC                      | Dana Showalter      |             |                               |
| 5 | Entergy Services, Inc.  | Tracey Stubbs       | Affirmative |                               |
| 5 | Exelon Nuclear  | Mark F Draper       | Affirmative |                               |
| 5 | First Wind  | John Robertson      |             |                               |
| 5 | FirstEnergy Solutions   | Kenneth Dresner     | Affirmative |                               |
| 5 | Florida Municipal Power Agency                                    | David Schumann      | Affirmative |                               |
| 5 | Great River Energy  | Preston L Walsh     |             |                               |
| 5 | Hydro-Québec Production   | Roger Dufresne      | Abstain     |                               |
| 5 | Independence Power & Light Dept.                                  | James Nail          | Affirmative |                               |



|   |   |                     |             |  |
|---|---|---------------------|-------------|--|
| 5 | Ingleside Cogeneration LP                                 | Michelle R DAntuono | Affirmative |  |
| 5 | JEA   | John J Babik        | Affirmative |  |
| 5 | Kansas City Power & Light Co.                             | Brett Holland       | Affirmative |  |
| 5 | Kissimmee Utility Authority                               | Mike Blough         | Affirmative |  |
| 5 | Lakeland Electric   | James M Howard      |             |  |
| 5 | Liberty Electric Power LLC                                | Daniel Duff         | Affirmative |  |
| 5 | Lincoln Electric System                                   | Dennis Florom       | Abstain     |  |
| 5 | Los Angeles Department of Water & Power                   | Kenneth Silver      | Affirmative |  |
| 5 | Lower Colorado River Authority                            | Dixie Wells         | Affirmative |  |
| 5 | Luminant Generation Company LLC                           | Rick Terrill        | Affirmative |  |
| 5 | Manitoba Hydro  | Chris Mazur         | Affirmative |  |
| 5 | Massachusetts Municipal Wholesale Electric Company        | David Gordon        | Abstain     |  |
| 5 | MEAG Power  | Steven Grego        | Affirmative |  |
| 5 | Muscatine Power & Water                                   | Mike Avesing        | Abstain     |  |
| 5 | Nebraska Public Power District                            | Don Schmit          | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 5 | Nevada Power Co.  | Richard Salgo       | Affirmative |  |
| 5 | New York Power Authority                                  | Wayne Sipperly      | Affirmative |  |
| 5 | NextEra Energy  | Allen D Schriver    | Affirmative |  |
| 5 | Northern Indiana Public Service Co.                       | Michael D Melvin    | Abstain     |  |
| 5 | Oglethorpe Power Corporation                              | Bernard Johnson     | Affirmative |  |
| 5 | Oklahoma Gas and Electric Co.                             | Henry L Staples     | Affirmative |  |
| 5 | Omaha Public Power District                               | Mahmood Z. Safi     | Affirmative |  |
| 5 | Orlando Utilities Commission                              | Richard K Kinas     |             |  |
| 5 | Pacific Gas and Electric Company                          | Alex Chua           | Abstain     |  |
| 5 | Platte River Power Authority                              | Christopher R Wood  | Affirmative |  |
| 5 | Portland General Electric Co.                             | Matt E. Jastram     | Affirmative |  |
| 5 | PPL Generation LLC  | Annette M Bannon    | Abstain     |  |
| 5 | PSEG Fossil LLC   | Tim Kucey           | Affirmative |  |
| 5 | Public Utility District No. 1 of Lewis County             | Steven Grega        |             |  |
| 5 | Public Utility District No. 2 of Grant County, Washington | Michiko Sell        |             |  |
| 5 | Puget Sound Energy, Inc.                                  | Lynda Kupfer        | Affirmative |  |
| 5 | Sacramento Municipal Utility District                     | Susan Gill-Zobitz   | Affirmative |  |
| 5 | Salt River Project  | William Alkema      |             |  |
| 5 | Santee Cooper   | Lewis P Pierce      | Negative    |  |
| 5 | Seattle City Light  | Michael J. Haynes   |             |  |
| 5 | Seminole Electric Cooperative, Inc.                       | Brenda K. Atkins    | Negative    |  |
| 5 | Snohomish County PUD No. 1                                | Sam Nietfeld        | Affirmative |  |
| 5 | South Carolina Electric & Gas Co.                         | Edward Magic        | Abstain     |  |
| 5 | Southern California Edison Company                        | Denise Yaffe        | Affirmative |  |
| 5 | Southern Company Generation                               | William D Shultz    | Affirmative |  |
| 5 | Tacoma Power  | Chris Mattson       | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 5 | Tennessee Valley Authority                                | David Thompson      | Negative    | COMMENT<br>RECEIVED                    |
| 5 | Tri-State Generation & Transmission Association, Inc.     | Mark Stein          | Negative    | COMMENT<br>RECEIVED                    |
| 5 | U.S. Army Corps of Engineers                              | Melissa Kurtz       | Abstain     |  |
| 5 | USDJ Bureau of Reclamation                                | Erika Doot          |             |  |
| 5 | Westar Energy   | Bryan Taggart       |             |  |
| 5 | Wisconsin Electric Power Co.                              | Linda Horn          | Negative    |  |
| 5 | Xcel Energy, Inc.   | Mark A Castagneri   | Affirmative |  |
| 6 | AEP Marketing   | Edward P. Cox       | Affirmative |  |
| 6 | Ameren Missouri   | Robert Quinlivan    | Affirmative |  |
| 6 | APS   | Randy A. Young      | Affirmative |  |
| 6 | Associated Electric Cooperative, Inc.                     | Brian Ackermann     | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 6 | Bonneville Power Administration                           | Brenda S. Anderson  | Affirmative |  |
| 6 | Calpine Energy Services                                   | Agus Bintoro        |             |  |
| 6 | City of Austin dba Austin Energy                          | Lisa Martin         | Affirmative |  |
| 6 | City of Redding   | Marvin Briggs       | Affirmative |  |

|    |  |                       |             |  |
|----|--|-----------------------|-------------|--|
| 6  | Cleco Power LLC  | Robert Hirchak        | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 6  | Colorado Springs Utilities                                   | Shannon Fair          | Negative    |  |
| 6  | Con Edison Company of New York                               | David Balban          | Affirmative |  |
| 6  | Constellation Energy Commodities Group                       | David J Carlson       | Affirmative |  |
| 6  | Dominion Resources, Inc.                                     | Louis S. Slade        | Negative    |  |
| 6  | Duke Energy  | Greg Cecil            | Affirmative |  |
| 6  | FirstEnergy Solutions  | Kevin Querry          | Affirmative |  |
| 6  | Florida Municipal Power Agency                               | Richard L. Montgomery | Affirmative |  |
| 6  | Florida Municipal Power Pool                                 | Thomas Reedy          | Affirmative |  |
| 6  | Florida Power & Light Co.                                    | Silvia P Mitchell     | Affirmative |  |
| 6  | Kansas City Power & Light Co.                                | Jessica L Klinghoffer | Affirmative |  |
| 6  | Lakeland Electric  | Paul Shipps           |             |  |
| 6  | Lincoln Electric System                                      | Eric Ruskamp          | Abstain     |  |
| 6  | Los Angeles Department of Water & Power                      | Brad Packer           | Abstain     |  |
| 6  | Lower Colorado River Authority                               | Michael Shaw          | Affirmative |  |
| 6  | Luminant Energy  | Brenda Hampton        |             |  |
| 6  | Manitoba Hydro   | Blair Mukanik         | Affirmative |  |
| 6  | Modesto Irrigation District                                  | James McFall          | Affirmative |  |
| 6  | Muscatine Power & Water                                      | John Stolley          | Affirmative |  |
| 6  | New York Power Authority                                     | Shivaz Chopra         | Affirmative |  |
| 6  | New York State Electric & Gas Corp.                          | Julie S King          | Abstain     |  |
| 6  | Northern Indiana Public Service Co.                          | Joseph O'Brien        | Abstain     |  |
| 6  | Oglethorpe Power Corporation                                 | Donna Johnson         | Affirmative |  |
| 6  | Oklahoma Gas and Electric Co.                                | Jerry Nottmangel      | Affirmative |  |
| 6  | Omaha Public Power District                                  | Douglas Collins       |             |  |
| 6  | PacifiCorp   | Sandra L Shaffer      | Negative    |  |
| 6  | Platte River Power Authority                                 | Carol Ballantine      | Affirmative |  |
| 6  | Portland General Electric Co.                                | Shawn P Davis         |             |  |
| 6  | Powerex Corp.  | Gordon Dobson-Mack    |             |  |
| 6  | PPL EnergyPlus LLC   | Elizabeth Davis       | Abstain     |  |
| 6  | PSEG Energy Resources & Trade LLC                            | Peter Dolan           | Affirmative |  |
| 6  | Public Utility District No. 1 of Chelan County               | Hugh A. Owen          | Abstain     |  |
| 6  | Sacramento Municipal Utility District                        | Diane Enderby         | Affirmative |  |
| 6  | Salt River Project   | William Abraham       | Affirmative |  |
| 6  | Santee Cooper  | Michael Brown         | Negative    |  |
| 6  | Seattle City Light   | Dennis Sismaet        | Affirmative |  |
| 6  | Seminole Electric Cooperative, Inc.                          | Trudy S. Novak        | Negative    |  |
| 6  | Snohomish County PUD No. 1                                   | Kenn Backholm         | Affirmative |  |
| 6  | South Carolina Electric & Gas Co.                            | Matt H Bullard        |             |  |
| 6  | Southern California Edison Company                           | Joseph T Marone       | Affirmative |  |
| 6  | Southern Company Generation and Energy Marketing             | John J. Ciza          | Affirmative |  |
| 6  | Tacoma Public Utilities                                      | Michael C Hill        | Negative    | SUPPORTS<br>THIRD<br>PARTY<br>COMMENTS |
| 6  | Tampa Electric Co.   | Benjamin F Smith II   |             |  |
| 6  | Tennessee Valley Authority                                   | Marjorie S Parsons    | Negative    |  |
| 6  | Westar Energy  | Grant L Wilkerson     |             |  |
| 7  | Luminant Mining Company LLC                                  | Stewart Rake          |             |  |
| 7  | Occidental Chemical  | Venona Greaff         | Affirmative |  |
| 7  | Siemens Energy, Inc.   | Frank R. McElvain     |             |  |
| 8  |  | David L Kiguel        | Affirmative |  |
| 8  |  | Roger C Zaklukiewicz  | Negative    |  |
| 8  | Massachusetts Attorney General                               | Frederick R Plett     | Affirmative |  |
| 8  | Volkman Consulting, Inc.                                     | Terry Volkman         |             |  |
| 9  | Central Lincoln PUD  | Bruce Lovelin         | Affirmative |  |
| 9  | Commonwealth of Massachusetts Department of Public Utilities | Donald Nelson         | Negative    |  |
| 9  | New York State Public Service Commission                     | Diane J Barney        | Affirmative |  |
| 10 | Midwest Reliability Organization                             | Russel Mountjoy       | Affirmative |  |
| 10 | New York State Reliability Council                           | Alan Adamson          | Affirmative |  |
| 10 | Northeast Power Coordinating Council                         | Guy V. Zito           | Negative    | COMMENT<br>RECEIVED                    |
| 10 | ReliabilityFirst   | Anthony E Jablonski   | Affirmative |  |
| 10 | SERC Reliability Corporation                                 | Joseph W Spencer      | Affirmative |  |



|    |  |                    |             |  |
|----|--|--------------------|-------------|--|
| 10 | Texas Reliability Entity, Inc.           | Karin Schweitzer   | Affirmative |  |
| 10 | Western Electricity Coordinating Council | Steven L. Rueckert | Affirmative |  |
|    |  |                    |             |  |

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**Exhibit I**

**Standard Drafting Team Roster**

# Project 2010-05.2 Special Protection Systems - Phase 2 of Protection Systems Standard Drafting Team

| Name and Title          | Company and Address  | Contact Info   | Bio  |
|-------------------------|--|--|--|
| Gene Henneberg<br>Chair | NV Energy<br>1 Ohm Place<br>PO Box 10100, Mail<br>Stop R60ST<br>Reno, NV 89520 | (775) 834-7187<br><a href="mailto:ghenneberg@nvergy.com">ghenneberg@nvergy.com</a>           | Gene has over 35 years electric utility experience in transmission planning, substation construction and operations, and system protection. Member of IEEE Power System Relaying Committee, vice chair of C subcommittee and member of numerous working groups including C-21, "IEEE Guide for Engineering, Implementation, and Management of System Integrity Protection Schemes." Member of the WECC Relay Work Group (20+ years), Remedial Action Scheme Reliability Subcommittee (15+ years, chair since 2008), drafting team chair for PRC-(012-014)-WECC-CRT-1 and -2 criteria, drafting team member for PRC-004-WECC-1, and member of Modeling SPS and Relays Ad-Hoc Task Force (MSRATF). Active observer in the present development of PRC-026-1 standard. Gene holds a BSE from Walla Walla College, MSEE from Washington State University, and is a registered Professional Engineer in the State of Nevada. |
| Bobby Jones Vice-Chair  | Southern Company Services<br>600 North 18th Street<br>Birmingham, AL 35203     | 205-257-6148<br><a href="mailto:rajones@southerncompany.com">rajones@southerncompany.com</a> | Bobby is currently the Planning Manager for Stability and Special Studies in the Transmission Planning Department at Southern Company Services. He has been managing this area for Southern for the past 20 years. In this role, he performs and oversees angular stability, voltage stability, UFLS, UVLS, SPS, and other studies. Earlier in his career, Bobby was involved in transient voltage analysis, harmonics studies, power quality, and surge protection. He has a total of 41  |

| Name and Title                            | Company and Address   | Contact Info   | Bio   |
|---|---|--|---|
|   |   |  | <p>years experience in the industry working for the Southern Company.</p> <p>Bobby served as a member of the NERC ATFNSDT Standard Drafting Team (TPL Standard), chairman of the SERC UFLS Standard Drafting Team, and chair of the NERC Project 2010-03 (MOD B) Standard Drafting Team.</p> <p>Bobby obtained a BSEE degree from the University of Alabama in 1973 and an MSEE degree from University of Alabama – Birmingham in 1978. He is a registered Professional Engineer in Alabama.</p>  |
| Davis Erwin                               | 6111 Bollinger Canyon Road<br>San Ramon, CA<br>94543                          | (925) 328-5453<br><a href="mailto:dpe4@pge.com">dpe4@pge.com</a>               | <p>Davis has 16 years of protection and control experience with Pacific Gas and Electric and is the technical lead for 500kV protection design, settings, and real time operational support. He also supports wide area Remedial Action Scheme design. He has a BS and MS degree in electrical engineering, is a registered professional engineer in California, is a member of the WECC Remedial Action Scheme Reliability Subcommittee, and is the SME for PG&amp;E's implementation of PRC-002-2.</p>  |
| John Ciufu<br>Principal<br>Owner/Engineer | CC Consulting Inc.<br>4048 Twine Crescent,<br>Mississauga,<br>Ontario, Canada | (647) 988-5163<br><a href="mailto:John.ciufo@bell.net">John.ciufo@bell.net</a> | <p>John professional electrical engineer with thirty-seven years of electric utility experience. I worked for Hydro One Inc., formerly Ontario Hydro from 1976 to 2010. Over the years, I have held many different positions and have considerable experience in such areas as: smart grid, asset management, development of strategies, policies, functional and design standards, engineering, regulatory compliance, cyber security, and was a corporate sponsor for many research and development projects. I completed my career with Hydro One as the Manager – Protection &amp; Control Strategies and Standards in Asset Management.</p> <p>I have extensive background in protection and control systems in the electric</p> |

| Name and Title               | Company and Address  | Contact Info   | Bio   |
|------------------------------|--|--|---|
|                              |  |  | <p>industry. I am a registered Professional Engineer in the Province of Ontario and was a member of the Northeast Power Coordinating Council (NPCC), Task Force on System Protection for ten years and a Vice-Chair from Jan 2008 to Jan 2010. I was a member of the North American Electric Regulatory Corporation (NERC), System Protection and Control Subcommittee from 2004 to 2010, and was the Chair between the periods June 2008 to September 2010. I was a member of the North American Electric Regulatory Corporation (NERC) Smart Grid Task Force. Presently, I am a principal owner of Ciufu &amp; Cooperberg Consulting Inc. (CCCI).</p> |
| <p>Charles-Eric Langlois</p> | <p>Hydro-Québec<br/>TransÉnergie<br/>Complexe<br/>Desjardins, tour<br/>Est, 9e étage, C.P.<br/>10000, succ. pl.<br/>Desjardins,<br/>Montréal, QC<br/>H5B 1H7</p> | <p>514-879-4100 ext.<br/>5441<br/><a href="mailto:langlois.charles-eric@hydro.qc.ca">langlois.charles-eric@hydro.qc.ca</a></p> | <p>Charles is currently an engineer in short-term planning of the transmission system at Hydro-Québec since 2008. Team leader since 2014. Main experience in stability studies for the design and operation of the BES (transfer capabilities and SPS design). Involved closely in planning and testing of 3500 MW of wind generation (various publications, including IEEE). Member of NPCC CO7-CP11 task force for the revision of BPS design criteria (Directory #1). Member of NERC UVLS SDT (project 2008-02) and former member of NERC IVGTF 1-1.</p>   |
| <p>Alan Engelmann</p>        | <p>ComEd<br/>2 Lincoln Centre<br/>Oakbrook Terrace,<br/>IL 60181</p>   | <p>(630) 576-6907<br/><a href="mailto:alan.engelmann@comed.com">alan.engelmann@comed.com</a></p>                               | <p>Alan is a Principal Engineer with ComEd, where he has been employed since 1989. His current position is in Transmission Planning where his responsibilities include technical analysis in the areas of generator stability, voltage stability, dynamic voltage recovery, SPS, and GMD. In addition to 15 years of experience in Transmission Planning, he has also held positions in Testing and Information Technology. He holds a BSEE from Valparaiso University, an MSEE from Purdue University, and is a registered Professional Engineer in the State of Illinois.</p>   |

| Name and Title    | Company and Address   | Contact Info   | Bio   |
|-------------------|---|--|---|
| Sharma Kolluri    | Entergy Services Inc,<br>639 Loyola Ave,<br>New Orleans. LA<br>70113  | (504) 576 4045<br><a href="mailto:vkollur@entergy.com">vkollur@entergy.com</a> | Sharma has over 30 years of experience in the Planning/Operations area. Currently he is Manager of Transmission Planning and responsible for advanced studies in power systems. His primary area of responsibility includes stability studies, generator interconnection studies, reactive power planning studies, SPS and UVLS. He was a member of the NERC Planning Standards III & IV Drafting Team. Generator Verification SDT, Member of the SERC Generator Standards Field Testing task force. Member of the NERC UVLS drafting team. Chairman of the Dynamics Review Sub committee at SERC. Sharma has MSEE from West Virginia University and is actively involved in IEEE PES activities. He is an IEEE Fellow. |
| Amos Ang          | Southern California Edison<br>3 Innovation Way<br>Pomona, CA<br>91768 | (909) 274-1631<br><a href="mailto:amos.ang@sce.com">amos.ang@sce.com</a>       | Amos Ang has 13 years of electric utility experience in Transmission Planning. Amos is the Relay Sub-group chair of the Modeling SPS and Relays Ad-Hoc Task Force (MSRATF), and is a member of the South West Arizona Transmission Short Circuit Duty Work Group. Amos also serves as a member of the NERC System Analysis and Modeling Subcommittee. Mr. Ang has a BSE degree in Electrical Engineering from California Polytechnic University of Pomona and is a licensed Professional Engineer in the state of California.   |
| Robert J. O'Keefe | 700 Morrison Rd,<br>Gahanna, Ohio<br>43230                            | 614 552-1658<br><a href="mailto:rjokeefe@aep.com">rjokeefe@aep.com</a>         | Mr. O'Keefe has over 30 years of experience in power system dynamic performance, system studies, and modeling including 24 years at AEP in Transmission Planning where he holds the position of Principal Engineer, and 7 years prior to joining AEP at General Electric. Mr. O'Keefe has served on a number of industry working groups and standard drafting teams including the RFC Special Protection System Review Team since 2007, the ERCOT Dynamics Working  |



| Name and Title     | Company and Address  | Contact Info   | Bio  |
|--------------------|--|--|--|
|                    |  |  | <p>Group since 2010, and the NERC Underfrequency Load Shedding Standard Drafting Team during 2007-2010 and as chairman of that team in its last year. Mr. O’Keefe earned Bachelor and Master of Science degrees in Electrical Engineering from Purdue University and is a licensed Professional Engineer in the State of Ohio.</p>   |
| <p>Hari Singh</p>  | <p>1800 LARIMER ST,<br/>SUITE 600,<br/>DENVER, CO 80202</p>                                    | <p>(303) 571 7095<br/><a href="mailto:hari.singh@xcelenergy.com">hari.singh@xcelenergy.com</a></p> | <p>Hari Singh has over 20 years of experience in planning, operations &amp; engineering of the bulk electric systems. He is a Principal Engineer in Transmission Planning (West) for Xcel Energy. Hari serves as a member (WECC Representative) of the NERC System Analysis &amp; Modeling Subcommittee (SAMS) and was an active participant in the development of 2013 NERC Report on Assessment of SPS and RAS Definition, Regional Practices &amp; Related Standards. Hari is also a member of the WECC Reliability Subcommittee, the WECC Modeling &amp; Validation Working Group, the WECC MSRATF (Modeling SPS and Relays Ad hoc Task Force), and the NERC UVLS Standard Drafting Team. Hari was also an active observer in the development of the TPL-001-4 standard.</p> |
| <p>Al McMeekin</p> | <p>NERC<br/>3353 Peachtree Rd.<br/>NE<br/>Suite 600, North<br/>Tower<br/>Atlanta, GA 30326</p> | <p>(404) 446-9675<br/><a href="mailto:Al.McMeekin@nerc.net">Al.McMeekin@nerc.net</a></p>           | <p>Al McMeekin is a Standards Developer with NERC. Prior to joining NERC in 2009, Mr. McMeekin worked at South Carolina Electric &amp; Gas Company (SCE&amp;G) for 29 years holding a variety of professional and supervisory positions within the distribution and transmission organizations. Al participated in SCE&amp;G’s ERO Working Group to ensure compliance with NERC standards; and represented SCE&amp;G on various national, regional, and sub-regional groups. Mr. McMeekin was a member of the SERC Operating Committee and served as Chair of the SERC Operations Planning Subcommittee. Al was a member of the</p>  |

| Name and Title | Company and Address  | Contact Info   | Bio   |
|----------------|--|--|---|
|                |  |  | <p>SERC Standards Committee and the SERC Available Transfer Capability Working Group. He also served as Chair of the VACAR South Reliability Coordinator Procedures Working Group, and was a member of Project 2006-03 (System Restoration and Blackstart – EOP-005 &amp; EOP-006) Standards Drafting Team. Al holds a BSAgE degree from Clemson University and is a registered Professional Engineer in South Carolina.</p>  |
| Lacey Ourso    | <p>NERC<br/>3353 Peachtree Rd.<br/>NE<br/>Suite 600, North<br/>Tower<br/>Atlanta, GA 30326</p> | <p>(404) 446-2581<br/><a href="mailto:lacey.ourso@nerc.net">lacey.ourso@nerc.net</a></p> | <p>Lacey Ourso is a Standards Developer with NERC. Prior to her time at NERC, Lacey was a civil litigation attorney, practicing in the State of Georgia. Her practice included representing engineers and business owners in regulatory and litigation matters. Lacey attended Louisiana State University for both her undergraduate and law school education. In 2003, she obtained a Bachelor of Science degree in Business Administration and then in 2006 her Juris Doctorate and Bachelor of Civil Law degree.</p> |